April 15, 2020

VIA ELECTRONIC FILING

The Honorable Kimberly D. Bose, Secretary
Federal Energy Regulatory Commission
888 First Street, NE
Washington, DC 20426

Re: ***ISO New England Inc.*****, Compliance Filing of Energy Security Improvements Addressing New England's Energy Security Problems; Docket Nos. EL18-182-000 and ER20-___-000**

Request for an effective date of November 1, 2020 and an order of the Commission on or before that date, and for an extended comment period of 30 days.

Dear Secretary Bose:

In compliance with the order of the Federal Energy Regulatory Commission ("Commission") dated July 2, 2018,[1] ISO New England Inc.[2] (the "ISO") hereby electronically submits this transmittal letter and revisions to the ISO New England Inc. Transmission, Markets and Services Tariff incorporating its comprehensive, long-term market enhancements, known as "Energy Security

[1] Order Denying Waiver Request, Instituting Section 206 Proceeding, and Extending Deadlines, 164 FERC ¶ 61,003 at P 55 (2018) (directing the ISO, pursuant to Schedule 206 of the Federal Power Act, to submit "permanent Tariff revisions reflecting improvements to its market design to better address regional fuel security concerns" upon finding that the "Tariff does not sufficiently address the fuel security issues currently facing the region, which could result in a violation of mandatory reliability standards") (the "July 2 Order"). *See* Notice of Extension of Time, Docket No. EL18-182-000, issued August 30, 2019. The Tariff rules filed here reflect a complete, sustainable, fully integrated market design to address the energy security problem facing the region in direct compliance with the Commission's directives pursuant to Section 206 of the FPA. To the extent the Commission finds any part of the proposed long-term, market-based solution filed here to be outside the scope of its directive, the ISO requests the Commission consider it under Section 205 of the FPA, and find it just and reasonable. If such a Commission finding relates to a part of the proposal for which NEPOOL supported an alternative, that proposal should be considered in accordance with Section 11.5 of the Participants Agreement.

[2] Capitalized terms used but not otherwise defined in this filing have the meanings ascribed thereto in Section I.2.2 of the ISO-NE Transmission, Markets and Services Tariff (the "Tariff"). Section III of the Tariff contains Market Rule 1, the Standard Market Design ("Market Rule 1").

Improvements." These enhancements are necessary to address the fuel security[3] challenges facing the New England region.

The region's challenges are caused by the inability of much of its evolving resource mix to store the fuel necessary to produce energy upon request, and the region's failure to compensate its fleet for the essential reliability services they provide. Therefore, to address the region's energy security challenges, the ISO proposes to improve the current market structure to create incentives for its fleet to invest in the energy supply arrangements and technologies on which the region depends.[4] The ISO submits these Tariff rules reflecting the Energy Security Improvements to achieve that objective, in full compliance with the Commission's directive for the ISO to file "Tariff revisions reflecting improvements to its market design to better address regional fuel security concerns."[5]

The New England Power Pool ("NEPOOL") Participants Committee did not support the Tariff provisions reflecting the ISO's Energy Security Improvements. NEPOOL, however, garnered sufficient support for an alternative proposal that amends the Energy Security Improvements in three discrete ways, but otherwise adopts the ISO's design. Had this filing been made pursuant to Section 205 of the Federal Power Act, NEPOOL's vote would have triggered the threshold for a "jump ball" pursuant to Section 11.5 of the Participants Agreement.[6] While the instant compliance filing is not covered by the "jump ball" provisions,[7] the ISO nonetheless agreed at the start of the stakeholder

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[3] The ISO in the past has referred to the problem facing the region as a *fuel security* problem, but what the region faces is more appropriately referred to as an *energy security* problem due to the constraints – and uncertainties – in managing an increasingly energy-limited power system consistent with established reliability standards and criteria. *See* Testimony of Peter T. Brandien, Vice President of System Operations and Market Administration of the ISO, provided as Attachment A with this filing ("Brandien Testimony"), at 4-5.

[4] *See* July 2 Order at PP 53-54 (reaffirming "support for market solutions as the most efficient means to provide reliable electric service to New England consumers at just and reasonable rates"). *See also ISO New England Inc.*, 165 FERC ¶ 61,202 at P 96 (2018), *reh'g pending* (the "December 3 Order") (stating, "We agree with the dissent that the value of these resources must be accurately reflected in the market in order to address fuel security issues in the *long-term*. Moving to a market-based approach as soon as possible is the best way to achieve that objective.") (emphasis added).

[5] *See* July 2 Order at P 55.

[6] Section 11.5 of the Participants Agreement (referred to as the "jump ball provision") requires that the ISO, as part of a Section 205 filing, present to the Commission any alternative Market Rule proposal that is approved by a Participant Vote of at least 60 percent in detail sufficient to permit reasonable review by the Commission, explain the ISO's reasons for not adopting the proposal, and provide an explanation as to why the ISO believes its own proposal is superior to the proposal approved by the Participants Committee. The Commission may then choose to "adopt any or all of the ISO's Market Rule proposal or the alternative Market Rule proposal as it finds, in its discretion, to be just and reasonable and preferable."

[7] *See ISO New England Inc*., *et al*. 145 FERC ¶ 61,110 at P 39 (2013):

> We reject NEPOOL's argument that the proposal set forth in its protest should be considered on equal footing with the Compliance Revisions. The jump ball provision is wholly inapplicable to this case involving a compliance filing submitted by ISO-NE, pursuant to the Commission's specific directive that ISO-NE submit such a filing as a result of a proceeding the Commission instituted

process to file any NEPOOL-approved alternative as if the jump ball provision applied. Accordingly, in fulfillment of this commitment, the ISO presents the NEPOOL-supported alternative, together with the requisite description and explanations, as part of this filing package in Section V of this filing letter. The Tariff sections reflecting the ISO's compliance proposal are contained in Attachments D-1 and D-2 of this filing. The Tariff sections reflecting the NEPOOL-supported alternative are contained in Attachments E-1 and E-2 of this filing.

The ISO respectfully requests that the Commission issue an order accepting the ISO's Tariff revisions, as filed, no later than November 1, 2020, to become effective November 1, 2020, as conditioned in Section VIII of this filing letter. The ISO further requests that the Commission establish a 30-day comment period. Such an extension is appropriate given the volume of this filing and the current circumstances. This will afford sufficient time for stakeholders to review and comment on the proposed market improvements, which represent a significant initiative for the region.

I. EXECUTIVE SUMMARY

This filing presents the ISO's long-term market-based solution to the region's energy security problems. In so doing, it fulfills the Commission's directives in Docket No. ER18-1509-000, in which the Commission instituted this proceeding pursuant to Federal Power Act Section 206. Below, the ISO summarizes the problem that necessitated the Energy Security Improvements, the Energy Security Improvements themselves, the Impact Assessment that substantiates the efficacy and cost-effectiveness of the Energy Security Improvements, and the need for the Commission to act expeditiously. The ISO also outlines the structure of this filing.

A. The Energy Security Problem

Historically, the resources comprising the New England fleet had large, ready stockpiles of fuel, ensuring that they could run whenever committed or dispatched. Accordingly, the ISO has always relied on its fleet to operate, without a day-ahead commitment or any compensation, in the event of a contingency such as a large loss of source or surge in demand.

Today's generation fleet looks markedly different than the fleet of twenty years ago. Primarily due to consistently low natural gas prices, the New England generation fleet now has substantial resources with "just-in-time" energy sources, rather than fuel stored on-site. In other words, there are many fewer stockpiles of coal and tanks full of oil; instead the region relies most on gas delivered through its constrained pipeline system. Over time, given the New England states' incentives, the

under section 206 of the FPA. We further reject NEPOOL's argument that, under the jump ball provision, the Commission 'may adopt any or all of ISO's Market Rule proposal or the alternative Market Rule proposal as it finds, in its discretion, to be just and reasonable and preferable,' regardless of whether ISO-NE is making a section 205 filing. NEPOOL's argument ignores the entire context of the jump ball provision, which applies to section 205 filings and not to Commission-ordered compliance filings that are the result of the Commission's exercise of its authority under section 206.

region's mostly-gas fleet will likely be joined by increasing numbers of renewable resources; these resources often have their own "just-in-time" fuel in the form of the sun and the wind.

Given the evolving power system, the current approach, which assumes there will be sufficient energy available each day in real-time from resources that have no day-ahead commitment, no longer works. As things stand, the ISO is concerned that the prevalence of resources with just-in-time inputs, combined with a constrained fuel delivery infrastructure, may not be able to produce energy in the event of an unexpected, extended loss of supply, particularly during stressed system conditions (*e.g.*, a cold snap). In other words, the region has an *energy security* problem.

B. The ISO's Proposed Solution and Impact Assessment Thereof

In studying the energy security problem and the existing markets and operations environments, the ISO identified certain gaps.[8] Specifically, these gaps relate to the assumptions about "free" resources that underlie the ISO's development of its daily Operating Plans.[9] These free resources fall into three distinct categories that correspond to specific reliability requirements:[10] energy to meet the gap between the ISO's forecast load in real-time and day-ahead physical energy supply awards; operating reserves for fast-start and fast-ramping generation contingency response; and energy to replace a long-duration supply loss or unanticipated increase in demand.

Essentially, in the absence of sufficient incentives, it is not economical for the current fleet to invest in the energy supply arrangements they need to run; the "free" resources are no longer free. Therefore, the markets must procure and provide compensation for the operational capabilities that these resources provide and the ISO depends on to ensure a reliable power system, so that resources are incented to invest in additional energy supply arrangements and the technologies that ensure these capabilities remain available to the power system each day. Moreover, to ensure a durable design, the enhanced markets must anticipate the needs and capabilities of the evolving generating fleet.

To fill the identified market gaps, the ISO proposes to formalize the three categories of operational capabilities identified above into specific ancillary services, and allow Market Participants

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[8] *See* ISO New England Inc., *Energy Security Improvements: Creating Energy Options for New England,* provided as Attachment B with this filing ("ESI White Paper"), dated April 15, 2020, at Section 2.

[9] Operating Plans refers to "processes and procedures which are available to the System Operator on a daily basis to allow the System Operator to reliably address conditions which may arise throughout the day. It is valid for tomorrow, the day after, and the day after that." *See* North American Electric Reliability Corporation ("NERC"), NERC-TOP-002-4 – Operations Planning, Section 4 (Associated Documents), https://www.nerc.com/pa/Stand/Reliability%20Standards%20Complete%20Set/RSCompleteSet.pdf ("NERC-TOP-002-4").

[10] The applicable reliability requirements are the ISO's, as well as those of NERC and the Northeast Power Coordinating Council ("NPCC").

to compete to provide those capabilities in the ISO's Day-Ahead Energy Market. These new ancillary services are: Day-Ahead Energy Imbalance Reserve ("EIR") to compensate all generators that work to satisfy the ISO's load forecast; Day-Ahead Generation Contingency Reserve ("GCR") to parallel the existing real-time operating reserves; and Day-Ahead Replacement Energy Reserve ("RER") to restore depleting operating reserves within reliability standards' prescribed timeframes and to address load forecast errors realized during the Operating Day (together, EIR, GCR and RER are referred to as the "Day-Ahead Ancillary Services").

The new Day-Ahead Ancillary Services are designed as options on energy; this approach allows for the creation of stronger incentives.[11] Energy options involve three settlement elements: (1) a sale of the option, which occurs at the option price; (2) a pre-determined strike price; and (3) the real-time price of the energy. The strike price is a pre-defined value, set before sellers specify their option offer prices and the market clears. It is similar to a threshold price in that it represents the maximum value the ISO (on behalf of load) is willing to pay for the energy option on a resource's electric energy during the Operating Day, in amounts and over timeframes that match the operational needs of the power system.

Offers to provide the Day-Ahead Ancillary Services ("Energy Call Option Offers" or "Option Offers") are voluntary, but if submitted must be accompanied by a physical resource with a corresponding offer for energy to ensure the cleared capability can be converted into energy in real-time. To ensure cost-effective outcomes, the Option Offers will be co-optimized (*i.e.*, simultaneously-cleared) in the Day-Ahead Energy Market, together with all energy supply offers and demand bids. The co-optimization process also ensures that the clearing prices for energy and each ancillary service incorporate the (marginal) suppliers' opportunity costs of foregoing a schedule for a different day-ahead product.

A Market Participant with cleared Option Offers to provide Day-Ahead Ancillary Services has a "no excuses" settlement obligation. If the resource does not produce energy in real-time, it will be charged based on the price of real-time energy if that price exceeds the applicable hour's pre-determined strike price.

To evaluate the efficacy and cost of its design, the ISO engaged the Analysis Group, Inc. ("Analysis Group"). In short, the Energy Security Improvements Impact Assessment (the "Impact Assessment") shows that the proposed design will create strong financial incentives for resources to maintain more secure energy supplies at a modest cost to consumers when compared to all ISO markets.[12] These incentives are greatest during periods when energy security risks are most severe, thereby creating the strongest price signals when energy needs are greatest. Further, while the strong improvements in energy security will increase costs to consumers, the Impact Assessment demonstrates

[11] *See* ESI White Paper, Sections 4 and 5.4. The proposal adopts an energy options design, which means the Day-Ahead Energy Market will procure options on real-time energy from physical resources; not ancillary services that settle against resources' anticipated real-time reserve designations.

[12] Impact Assessment, Section I.

that those increases come from a market design that lowers overall production costs for the region during more stressed system conditions, a critical indicator that the design enhances the region's energy security in an efficient manner.

C. Corresponding Changes

To allow the Energy Security Improvements to operate most effectively, the ISO proposes to eliminate two interim out-of-market programs that were designed to bridge the gap to the implementation of the long-term market design; the market design can only function if it can competitively price the reliability need without interference from out-of-market measures that provide the same services under a non-market price. Accordingly, assuming the Commission approves the Energy Security Improvements filed herewith, the ISO proposes to sunset the Fuel Security Retention Mechanism[13] (as invited by the Commission[14]) and the Inventoried Energy Program[15] before the beginning of the Capacity Commitment Period for the fifteenth Forward Capacity Auction ("FCA 15"), which coincides with the proposed implementation date of June 1, 2024 for the Energy Security Improvements.

The ISO also proposes to revise Appendix A of Market Rule 1 to add a new ad hoc reporting requirement for the Internal Market Monitor regarding the overall competitiveness and performance of the New England Markets, including major market designs. This change is responsive to stakeholder concerns regarding the competitiveness and performance of the Energy Security Improvements. The new language will require the Internal Market Monitor to issue ad hoc reports on the competitiveness of any major market design change within one year of the effective date of operation, and on its performance within three years, in each case subject to adequate available data.

D. Need for Prompt Commission Action to Facilitate Implementation

To facilitate implementation of the Energy Security Improvements by June 1, 2024, as reflected in the Tariff rules, the ISO respectfully requests that the Commission issue an order accepting the rules, as filed, no later than November 1, 2020, to become effective November 1, 2020, as conditioned in Section VIII of this filing letter.

An order on the requested effective date will provide Market Participants with certainty regarding applicable market rules as they participate in qualification activities for FCA 15, which will run in February 2021. An order is also necessary to inform the development of various parameters for

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[13] *See* Tariff at §§ III.13.2.5.2.5A and III.L ("Fuel Security Retention Mechanism"). *See also* December 3 Order, 165 FERC ¶ 61,202.

[14] December 3 Order at PP 96-97.

[15] *See* Tariff at §§ III.K ("Inventoried Energy Program"). *See also ISO New England, Inc.*, Inventoried Energy Program, Docket No. ER19-1438-000 (March 25, 2019), *effective by* Notice of Filing Taking Effect by Operation of Law (August 6, 2019); *order on reh'g,* Notice of Denial of Rehearing by Operation of Law re ISO New England Inc. (October 7, 2019).

the sixteenth Forward Capacity Auction ("FCA 16"); those parameters must be filed in advance of the qualification process for FCA 16, which will begin in spring 2021.

Prompt Commission action is also necessary to support the implementation of the Energy Security Improvements, which is a large, complex, and multi-year project. This work will include the development of a mitigation proposal and a seasonal forward market to complement the Day-Ahead Ancillary Services. The ISO must also engage in internal work to resolve all design, technical, and implementation details, including the interplay between the Day-Ahead Ancillary Services and other markets, including the Forward Reserve Market, and integration with related market rules such as the Net Commitment Period Compensation rules and financial assurance requirements. These conforming changes must be vetted with stakeholders and filed with the Commission.

Finally, certainty about the rules is necessary to facilitate key software development activities, including modifying several existing bid-to-bill software systems and building novel capabilities in coordination with vendors. Software work will entail development of detailed business requirements and technical specifications, coding, application testing, and system-wide integrated testing. This work must be coordinated with ongoing upgrades to the Day-Ahead Energy Market software.

E. Conclusion and Structure of Filing

In sum, the new Day-Ahead Ancillary Services will ensure that Market Participants have incentives to provide the capabilities needed to ensure that the system can respond when the region faces the types of real-time stressed system conditions that have created concerns over energy security in the past. In so doing, the design will also provide stronger and more accurate price signals to suppliers during tightening market conditions, including those related to fuel limitations; conversely, when energy security risks are low, costs will fluctuate accordingly, to the benefit of consumers. Finally, the design meets the Commission's directive and the ISO's goal of durability in the face of a changing grid; as intermittency increases, the Energy Security Improvements will procure operational capabilities to balance the system and, as the design is fuel-and technology-neutral, will compensate any new technologies that can provide the services.

The rest of this filing letter supports the ISO's request that the Commission adopt the Energy Security Improvements, effective November 1, 2020. Specifically, the filing letter includes the following sections:

- Section II (Background), which describes the genesis of the energy security problem, and actions taken by the region to date to ameliorate that problem;

- Section III (the Energy Security Problem), which outlines the issues related to incentives that the design addresses and references the ISO's white paper entitled "Energy Security: Creating Energy Options for New England" and attached hereto;

- Section IV (Overview of the Energy Security Improvements and their Expected Impacts), which includes a discussion of the Analysis Group's Impact Assessment along with a high-level description of the design;

- Section V (Detailed Explanation of the Energy Security Improvements and the NEPOOL Alternatives), which provides a feature-by-feature description of the design and three discrete changes preferred by stakeholders;

- Section VI (Tariff Revisions Incorporating the Energy Security Improvements and Comporting Changes), which outlines proposed Tariff revisions for the new Day-Ahead Ancillary Services and the three related changes proposed herein;

- Section VII (Implementation Work and Schedule), which details the work required to implement the Energy Security Improvements and the need for certainty regarding the Commission's approval of the rules accompanying this filing letter;

- Section VIII (Requested Effective Date and Commission Order), which describes the need for an effective date of, and order by, November 1, 2020;

- Section IX (Stakeholder Process), which substantiates the robust process by which stakeholders reviewed the Energy Security Improvements and related changes;

- Section X (Documents Enclosed);

- Section XI (Communications); and

- Section XII (Conclusion).

As detailed in Section X, the ISO also provides attached testimony and supporting documents, including most notably:

- Brandien Testimony, explaining the operational requirements underlying the Energy Security Improvements' Day-Ahead Ancillary Services, and the energy security concerns warranting the need for these new, market services (Attachment A);

- Affidavit of Dr. Matthew White, Chief Economist of the ISO, accompanying the ESI White Paper that describes in detail the underlying causes of New England's energy security problems and how the Energy Security Improvements will address them (Attachment B); and

- Affidavit of Dr. Todd Schatzki, a Vice President at Analysis Group, accompanying the Impact Assessment, which provides the results of the quantitative analysis of the Energy Security Improvements' expected impacts, while also demonstrating how the design is expected to improve incentives for energy security and reliability (Attachment C).

II. BACKGROUND

On May 1, 2018, in Docket No. ER18-1509-000, the ISO petitioned for waiver of certain Tariff provisions to prevent the retirement of the Mystic Generating Station ("Mystic") in Massachusetts until June 1, 2024, given the region's fuel-security reliability challenges in winter. In rejecting the ISO's waiver petition and instituting this proceeding pursuant to Federal Power Act Section 206,[16] the Commission reaffirmed its "support for market solutions as the most efficient means to provide reliable electric service to New England consumers at just and reasonable rates" and established expectations for the ISO to "develop longer-term market solutions."[17] Specifically, the Commission directed the ISO to develop and file longer-term market solutions "reflecting improvements to its market design to better address regional fuel security concerns."[18]

In the remainder of this section, the ISO outlines the energy security concerns underlying its initial request, and its attempts to ameliorate them, culminating in this filing.

A. The Region's Energy Security Concerns

As described in the Brandien Testimony, industry and policy trends are changing the makeup of New England's power system.[19] Over nearly two decades, because of consistently low natural gas prices and New England states' incentives for renewable resources, the New England generation fleet has incorporated growing numbers of natural gas-fired and renewable resources with just-in-time energy sources, while more and more resources with fuel stored on-site are being retired. Indeed, the majority of the region's electricity, both currently and in the foreseeable future, is likely to come from natural gas-fired resources and intermittent energy sources. However, the operational capabilities (*i.e.*,

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[16] July 2 Order at P 55.

[17] *See id*. at PP 53-54. *See also* December 3 Order at P 96.

[18] *See* July 2 Order at P 55:

> Based on the evidence in this proceeding, including ISO-NE's OFSA and Mystic Retirement Studies, we are concerned that ISO-NE's Tariff does not sufficiently address the fuel security issues currently facing the region, which could result in a violation of mandatory reliability standards. Accordingly, pursuant to FPA section 206, we direct ISO-NE either: (1) to submit within 60 days of the date of this order interim Tariff revisions that provide for the filing of a short-term, cost-of-service agreement to address demonstrated fuel security concerns and to submit by July 1, 2019 permanent Tariff revisions reflecting improvements to its market design to better address regional fuel security concerns; or (2) within 60 days of the date of this order, to show cause as to why the Tariff remains just and reasonable in the short- and long-term such that one or both filings is not necessary.

See also id. at PP 2, 49.

[19] *See* Brandien Testimony at 4, 23-26. *See also* Energy Security Improvements: Market Solutions for New England, Speaker materials of Matt White and Chris Parent, ISO New England, at the ISO New England Fuel Security Noticed Meeting, Docket No. EL18-182-000 (filed July 15, 2019), at 9-11 ("July 15 Presentation").

capabilities to provide energy upon request in real-time or energy reserves) on which the ISO relies as part of its daily, next-day Operating Plans have historically been provided by resources with on-site "input" energy sources.[20]

In 2018, gas-fired generators provided 49 percent of New England's electric energy generation (excluding imports and behind-the-meter resources), up from just 15 percent in 2000.[21] Coal- and oil-fired generation accounted for just one percent each of New England's electric generation in 2018, down from 18 percent and 22 percent, respectively, in 2000.[22] Solar generation capacity has grown from just 40 MW in 2010 to 2,900 MW in 2018, and is projected to reach 6,700 MW in 2028.[23] As of April 1, 2019, proposed solar photovoltaic and wind generation facilities comprised more than 76 percent of the nameplate capacity of proposed new resources in the ISO's interconnection queue.[24]

While these trends comport well with the New England states' goals for a cleaner, greener regional power grid, they pose growing challenges to reliable system operations.[25] Both natural gas-based generation and renewable technologies rely on the just-in-time delivery of their energy sources. When the region's natural gas pipeline capacity is constrained, natural gas-fired generation becomes a just-in-time energy supply unsuitable to provide energy upon request in real-time[26] – and increasing reliance on gas-fired generating capacity further exacerbates the constraints. Though the system's additions of renewable resources reduce energy security risk to an extent, the energy output of such resources inherently varies with the weather and, absent additional technologies, they are unable to provide energy on demand in real-time. This leaves the region reliant on the remaining oil-fired and coal resources to cover that energy supply gap, which may not be feasible in the long-term given that they are at risk of retirement.[27]

With the power system's continuing trend away from resources capable of providing energy on-demand in real-time, the ISO is increasingly concerned that there may be insufficient energy available to the New England power system to satisfy electricity demand and maintain reserves when

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[20] *See* Brandien Testimony at 4-5, 23-26.

[21] *See id*. at 24. *See also* July 15 Presentation at 6.

[22] *See id*.

[23] *See id*.

[24] *See id*. The ISO's interconnection queue is available on the ISO's website at https://www.iso-ne.com/system-planning/transmission-planning/interconnection-request-queue.

[25] *See* Brandien Testimony at 24-26. *See also* Pet. of ISO New England Inc. for Waiver of Tariff Provision, Exhibit ISO-1, *ISO New England Inc.*, Docket No. ER18-1509-000 (May 1, 2018) (describing the New England region's constrained fuel infrastructure and growing dependence on just-in-time energy sources).

[26] *See* July 15 Presentation at 7-10.

[27] *See id*. at 7-8.

grid operating challenges arise (*e.g.*, an extended cold winter period), and that the market may not appropriately signal tightening conditions preceding an actual scarcity in supply.[28] While there has been no loss of load attributable to insufficient energy supplies to date, the ISO is concerned that, given industry trends, these risks will worsen over time unless proactive solutions are developed.

B. Efforts to Ameliorate the Energy Security Concerns

Over the past decade, the ISO, together with regional stakeholders, has made significant market and operational enhancements to address the challenges presented.[29] Many of these improvements have been driven by the recognition that, to support the reliable operation of the bulk power system, the ISO's administered markets must do a better job of reflecting scarcity. When scarcity is properly priced, the markets appropriately compensate and incent cost-effective investments in resources and capabilities that are necessary to help ensure reliability when it is needed the most. The market improvements pursued over time have enhanced the ISO's suite of markets in various ways, providing considerably greater flexibility for resources to update energy offer prices during the Operating Day as their fuel costs change and to facilitate the inclusion of opportunity costs in energy market offers, and greatly strengthening the market's price signals for energy and reserves during scarcity conditions.[30] The operational improvements include the development of twenty-one-day forward-looking forecasts to inform Market Participants of expected energy supply conditions.[31]

While pursuing operational and market improvements, the ISO also undertook out-of-market actions focused on shoring-up key facilities' fuel stocks to alleviate near-term fuel security risks. The most notable of these actions is the temporary retention of Mystic, pursuant to the Commission-accepted Fuel Security Retention Mechanism. The use of this blunt tool was intended to delay the loss of this

[28] *See* Brandien Testimony at 24-26.

[29] *See* July 2 Order at P 53 (recognizing that "ISO-NE has recently implemented important steps to further strengthen its markets, with new market rules designed to help address fuel security issues that underlie this proceeding.").

[30] These enhancements include the implementation of hourly offer flexibility in the energy market, *see ISO New England Inc.*, Energy Market Offer Flexibility Changes, Docket No. ER13-1877-000 (filed July 1, 2013), Order Conditionally Accepting Tariff Revisions, 145 FERC ¶ 61,014 (2013), and Order Accepting Tariff Revisions, 147 FERC ¶ 61,073 (2014); the procurement of replacement operating reserves with pricing in the Real-Time Energy Market, *see ISO New England Inc.*, Revisions to Market Rule 1 to Establish a Reserve Constraint Penalty Factor for a Replacement Reserve Requirement, Docket No. ER13-1736-000 (filed June 20, 2013), accepted *ISO New England Inc.*, Docket ER13-1736-000 (August 15, 2015) (delegated letter order) ("Replacement Reserve Order"); increasing the Reserve Constraint Penalty Factors to more accurately reflect the marginal value of reserves during times of scarcity, *see ISO New England Inc.*, Compliance Filing of Two-Settlement Forward Capacity Market Design, Docket No. ER14-2419-000 (filed July 14, 2014), order accepting in part and rejecting in part, *ISO New England Inc.*, 149 FERC ¶ 61,009 (2014), *reh'g denied ISO New England Inc.*, 153 FERC ¶ 61,224 (2015); implementing the pay-for-performance capacity market enhancement, *see ISO New England Inc.*, Pay For Performance Enhancements, Docket No. ER18-1223-000 (filed March 29, 2018), accepted *ISO New England Inc.*, Docket ER18-1223-000 (May 11, 2018) (delegated letter order).

[31] *See* ISO New England Operating Procedure No. 21 – Energy Inventory Accounting and Actions During an Energy Emergency,
https://www.iso-ne.com/static-assets/documents/rules_proceds/operating/isone/op21/op21_rto_final.pdf.

generating resource and its reliable on-site fuel source to provide the region with time to further develop long-term solutions to the region's energy security problem. The ISO also developed a temporary Inventoried Energy Program, to be in effect for the winters of 2023-2024 and 2024-2025.[32] This mechanism will provide incentives for resources to maintain inventoried energy that contributes to reliable operations during cold winter conditions.

Since the July 2 Order, the ISO and regional stakeholders have been engaged in efforts to evaluate and develop a long-term, market-based path forward, consistent with the July 2 Order's directives. To achieve that objective, the ISO undertook a deeper analysis of the cause of the energy security problem from a market perspective.[33] The ISO's analysis identified certain gaps in the current market structure that are contributing to the energy security problem.[34] Specifically, these gaps relate to the assumptions underlying the ISO's development of its daily Operating Plans.

As the Brandien Testimony explains, the ISO, as the NERC-registered Reliability Coordinator, Balancing Authority, and Transmission Planner for New England, is required to have next-day Operating Plans in place that ensure the power system is prepared for, and has the capabilities to manage, a range of uncertainties and supply limitations that can arise during the Operating Day under established reliability standards.[35] Historically, many of the resources comprising the New England fleet had large, ready stockpiles of fuel and could operate when committed or dispatched (*i.e.*, could provide energy on demand).[36] Thus, if a day-ahead scheduled resource was unable to operate unexpectedly, creating an 'energy gap' between demand and scheduled supply, there was always sufficient capability from other resources (capability without day-ahead schedules) that could provide energy on demand.

However, with the region's growing transition to more just-in-time energy sources and its constrained fuel delivery infrastructure, there may not always be sufficient unscheduled resource capability available to meet the reliability requirements inherent in the ISO's next-day Operating Plans. Nevertheless, the ISO must maintain reliable system operations, even when renewable resources experience adverse weather or gas pipelines are constrained, or both. Therefore, the ISO must ensure that, as the power system changes, it remains capable of providing both energy and reserves to maintain reliable operation of the grid.

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[32] *See* Tariff at § III.K.

[33] *See* ESI White Paper, Sections 1.1, and 2.

[34] *See id*. at Section 2.

[35] *See* Brandien Testimony at 3-5.

[36] *See id*.

As discussed below, the Energy Security Improvements address the mismatch between the assumptions underlying the ISO's operational planning and the region's evolving resource mix.[37]

III. THE ENERGY SECURITY PROBLEM

As discussed in Section 2 of the ESI White Paper, to comply with the July 2 Order's directive, the ISO undertook further analysis of the energy security problem. Logically, as the ESI White Paper explains, reducing the risks that arise in a power system increasingly reliant on just-in-time energy sources, such as New England's, requires additional sources of energy supply (or reductions in demand) when gas pipelines are most constrained, renewable resources experience adverse weather, or both.[38] Indeed, additional energy supply arrangements (*e.g.*, fuel) can enable the existing fossil-fired generators to perform reliably during such conditions.[39] However, the ISO's assessment identified that the current ISO-administered wholesale electricity markets (which were not originally designed for the challenges presented by just-in-time technologies) do not provide adequate financial incentives for Market Participants to make additional investments in energy supply arrangements that would be cost-effective and benefit the power system at times of heightened risk.[40]

The ESI White Paper identifies three interrelated market and operations problems in the current market design that can adversely affect the efficacy and reliability of the New England power system.[41] The first problem is one of "misaligned incentives" for energy supply arrangements, which occurs when Market Participants' private incentives to take action to improve their resources' ability to provide energy supply in real-time do not align with society's interests in such arrangements.[42] This problem precipitates the second and third problems.

The second problem, operational uncertainties, relates to the concern that there may be insufficient energy available to the power system to withstand an unexpected, extended (multi-hour to multi-day) large generation or supply loss during stressed system conditions, because the resources the

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[37] Section 2 of the ESI White Paper examines the identified energy security problems, and Section 4 explains the market design solution to those problems.

[38] *See* ESI White Paper, Section 1.

[39] *See id*. Short-term examples may include arrangements by natural gas-fired generation to procure and maintain liquefied natural gas ("LNG") at existing LNG facilities in the Northeast (for use when the interstate pipelines are constrained during winter), and advance arrangements for fuel oil supplies to be promptly replenished during winter at the region's dual-fuel (oil and gas) and oil-based power plants. Longer-term examples may include a broader array of capital investments, such as greater price-sensitive demand participation in the wholesale markets, local "satellite" LNG storage facilities near generation stations, and innovative electricity storage technologies (like grid-scale batteries) that can smooth out the intermittency of renewable energy resources.

[40] *See id*.

[41] *See id*. at Section 2.1.

[42] *See* ESI White Paper, Section 2.2.

ISO relies on to address such energy gaps are those most likely to suffer from the misaligned incentives problem.[43] The third problem is insufficient day-ahead scheduling, which occurs when Market Participants procure less energy in the Day-Ahead Energy Market than the ISO's forecast energy demand for the next Operating Day. Each of these problems is briefly discussed below.[44] In addition to explaining these problems in detail, Section 2 of the ESI White Paper illustrates, through numerical examples, the challenges they present.

Importantly, what the identified problems reveal is that the current wholesale electricity markets are incomplete. They do not procure, or fully compensate resources, for the entire suite of operational capabilities that the ISO depends on to ensure reliable Operating Plans each day. Further, the resources that the ISO relies on for the system's operational needs – *i.e.*, resources without day-ahead schedules – face inefficiently low market incentives to invest in energy supply arrangements necessary to provide their capabilities reliably, even when such arrangements would be a cost-effective means to reduce reliability risks. Consequently, the resources may not have sufficient energy to operate should an energy gap arise during the Operating Day. This, in turn, could result in violations of mandatory reliability standards.

Therefore, as the ESI White Paper concludes, it is critical for the markets to provide the resources supplying the operational capabilities that the ISO depends on with efficient incentives to make energy supply arrangements, so they can operate reliably when stressed system conditions occur – including potentially extended cold periods.

A. Fundamental Problem: Misaligned Incentives

The fundamental problem identified in the ESI White Paper is a misalignment of private investment and society's interests for energy supply arrangements.[45] As explained therein, Market Participants whose resources face production uncertainty, absent a day-ahead schedule, may have inefficiently low incentives to invest in additional energy supply arrangements, even though such arrangements would be cost-effective from society's standpoint as a means of reducing reliability risks. This is because investing in more robust energy supply arrangements entails up-front costs, and in today's market construct, it is unprofitable for a resource that faces production uncertainty to incur the costs for energy supply arrangements it does not expect to use.

The ESI White Paper identified three root causes for the misaligned incentives problem.[46] The first root cause is resource production uncertainty: if a resource owner faces production uncertainty, it may have inefficiently low incentives to invest in additional energy supply arrangements, even when

[43] *See id*. at Section 2.6.

[44] *See id*.

[45] *See id*. at Sections 2.2-2.5.

[46] *See id*. at Section 2.5.

such arrangements would be beneficial from society's standpoint. The second relates to up-front costs: making supplemental arrangements in advance entails an up-front cost investment that the resource owner would have to incur in advance of learning whether it will be on demand (*i.e.*, asked to operate). The third root cause relates to the resource's materiality on potential outcomes: if the resource owner does not make energy supply arrangements in advance, then there is a chance that, without the resource, the real-time price will be higher, or reliability will be worse, than if the resource owner did make advance arrangements.

As the ESI White Paper illustrates, the misaligned incentives problem can present adverse efficiency and reliability consequences, if left unaddressed.[47] This is because the resources impacted by this problem – *i.e.*, those most likely to face inefficiently low market incentives to invest in energy supply arrangements so they can operate when needed – are the resources without day-ahead commitments that the ISO depends on to fill energy gaps in Operating Plans.[48] If such a resource does not have an energy source to enable its operation during a system-stressed condition, such as an extended cold weather period, then there is an increasing likelihood that the price for energy in real-time will be set by either the next most expensive resource or scarcity pricing that signals a deficiency of energy and reserves.

In sum, the market's failure to provide sufficient incentives for resource owners to invest proactively in additional energy supply arrangements can result in inefficient outcomes (higher expected costs to society), and adverse reliability consequences.

B. Second and Third Problems: Operational Uncertainties and Insufficient Day-Ahead Schedules

The misaligned incentives problem manifests the remaining problems concerning operational uncertainties and insufficient day-ahead scheduling.[49] As noted above, with the region's growing dependence on just-in-time energy sources and its constrained fuel delivery infrastructure, Market Participants that do not expect their generating resources to run the next day (*i.e.*, that do not receive a day-ahead schedule), but on which the ISO depends, may not have sufficient energy to operate, unless they made additional energy supply arrangements in advance. Consequently, there may be insufficient

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[47] *See* ESI White Paper, Sections 2.2-2.3.

[48] For clarity, as discussed in the ESI White Paper, most resources that clear in the Day-Ahead Energy Market successfully operate during the hours for which they received a Day-Ahead schedule. *See id*. at Sections 2.6-2.7. The types of existing resources facing production uncertainty, but relied on by the ISO to manage uncertainties (*i.e.*, the operational needs) include: (1) off-line fast-start dispatchable generators, which infrequently receive schedules in the Day-Ahead Energy Market (*e.g.*, hydro electric and distillate-fuel combustion turbines and internal-combustion units); (2) higher-cost 'blocks' of combined-cycle generators that receive schedules in the Day-Ahead Energy Market below their Economic Maximum Limit; (3) higher heat-rate combined-cycle generators that infrequently clear in the Day-Ahead Energy Market; and (4) long-lead time oil-steam units that infrequently clear in the Day-Ahead Energy Market. *See id*. at Section 2.6.2.

[49] *See id*. at Section 2.6.

energy available to the power system to withstand an unexpected, extended (multi-hour to multi-day) large generation or supply loss, particularly during stressed system conditions (*i.e.*, an extended cold weather period), resulting in a violation of mandatory reliability standards.[50] Additionally, when Market Participants procure less energy in the Day-Ahead Energy Market than the ISO's load forecast of real-time demand the next day, the Day-Ahead Energy Market, which does not currently incorporate that forecast, could clear less generation and (net) imports into New England than needed to cover the region's forecast energy demand for the next day.[51]

As the Brandien Testimony explains, the ISO must have an Operating Plan for the following day's system operations, and each Operating Plan must conform to applicable NERC and NPCC standards and criteria, as well as the ISO's operating procedures.[52] Specifically, in accordance with NERC Reliability Standard TOP-002-4 – Operations Planning, Requirement R.4, the ISO is required to develop next-day Operating Plans that address expected generation resource commitment and dispatch, interchange scheduling, demand patterns, and capacity and energy reserve requirements.[53] Each next-day Operating Plan must include the ISO's arrangements to supply energy when contingencies, such as a large loss of source or surges in demand, put the system under unexpected stress.

In accordance with processes set forth in ISO New England Governing Documents, including Market Rule 1 and System Operating Procedures, the ISO ensures sufficient resources are available to meet hourly demand (load) and operating reserve requirements for the next Operating Day.[54] In practice, as the Brandien Testimony explains, the Day-Ahead Energy Market outcomes (*i.e.*, resource commitments and scheduled interchange) form the basis for the ISO's next-day Operating Plans for the

[50] *See id*.

[51] *See* ESI White Paper, Section 2.6.

[52] *See* Brandien Testimony at 6-7.

[53] *See* Brandien Testimony at 6-12. Operating Reserve, as defined by NERC, is the "capability above firm system demand required to provide for regulation, load forecasting error, equipment forced and scheduled outages and local area protection. It consists of spinning and non-spinning reserves." *See* Glossary of Terms Used in NERC Reliability Standards, https://www.nerc.com/pa/Stand/Glossary%20of%20Terms/Glossary_of_Terms.pdf ("NERC Glossary of Terms"). Reserves encompass a number of different requirements, functions, and purposes within the multi-day time horizon of a Balancing Authority's Operating Plans.

[54] *See* Tariff at § III.1.10.1(d):

> Scheduling encompasses the Day-Ahead and hourly scheduling process, through which the ISO determines the Day-Ahead Energy Market schedules and determines, based on changing forecasts of conditions and actions by Market Participants and system constraints, a plan to serve the hourly energy and reserve requirements of the New England Control Area ...

See also SOP-RTMKTS.0050.0010 - Perform Reserve Adequacy Assessment, https://www.iso-ne.com/static-assets/documents/rules_proceds/operating/sysop/rt_mkts/sop_rtmkts_0050_0010.pdf.

region's power system.[55] Following the Day-Ahead Energy Market clearing, both the day before and during the Operating Day, the ISO performs assessments and, if necessary, commits additional resources using out-of-market tools to meet forecasted energy demand and operating reserve requirements.[56]

Presently, as the Brandien Testimony explains, the ISO relies on available resources' capabilities, above and beyond their day-ahead energy schedules, to satisfy the next-day Operating Plan's requirements and maintain a reliable power system.[57] These capabilities, and the corresponding reliability standards and the energy gaps they help fill, fall into the following three broad categories:

- *Forecast load-imbalance reserves.* This capability provides energy to cover any energy gap when the total energy supply cleared in the Day-Ahead Energy Market from physical resources (*e.g.*, generation and (net) imports into New England) is insufficient to serve the forecast electricity demand for the next Operating Day. Under NERC-TOP-002-4 – Operations Planning, the ISO's Operating Plan for the next day must ensure there is sufficient energy to cover the forecast load each hour – not simply the level of demand cleared in the Day-Ahead Energy Market. When the Day-Ahead Energy Market's cleared demand (less any net virtual supply) is less than the ISO's forecast load for one or more hours the next day, the energy to cover that load-balance gap is supplied through the dispatch and post-market commitments of other resources operating above, or that did not receive, a Day-Ahead Energy Market schedule.[58] The residual energy required to balance

[55] *See* Brandien Testimony at 18-21.

[56] *See id*.

[57] *See id*. at 17-18.

[58] *See id*. at 19-21. Today, Day-Ahead Energy Market resource commitment and scheduled interchange provide the basis for most of the ISO's next-day Operating Plan. The current Day-Ahead Energy Market employs a single energy demand curve, and a single energy balance constraint, and offered energy supply is cleared against bid-in energy demand, yielding an hourly commitment schedule for each cleared supply resource. The Day-Ahead Energy Market does not consider the ISO's forecast load requirement. After the Day-Ahead Energy Market clearing, the ISO applies its forecast energy requirement constraint as part of the out-of-market, uncompensated, RAA process. *See* Tariff at § 1.2.2 (defining, RAA as the "the analysis performed by the ISO to determine if adequate Resources are committed to meet forecasted load, Operating Reserve, and security constraint requirements for the current and next Operating Day.").

As the Brandien Testimony describes, in the RAA, the ISO reviews the difference between the ISO forecast load and the total (physical) resources and (net) imports that cleared in the Day-Ahead Energy Market, to assess the adequacy of the system's reserves, and to identify any additional actions necessary to ensure a reliable next-day Operating Plan. In this process, the ISO performs assessments to determine whether the total capabilities of all physical supply resources committed in the Day-Ahead Energy Market and the available fast-start resources are sufficient to cover the forecast energy requirement (*i.e.*, the residual energy needed), and to cover the system's reserve requirements for the hour. If not, the RAA optimization out-of-market tools will indicate which additional resources would be most cost-effective to commit to meet the system's forecast energy requirement and reserve requirements.

forecast energy supply with energy demand varies significantly from day-to-day and often within a day.[59]

- *Operating reserves for fast-start and fast-ramping generation contingency response.* This capability provides fast-start/fast-ramping generation contingency response, which enables the system to promptly restore the gap between energy supply and demand following an unanticipated supply loss (consistent with the timeframes specified in NERC BAL-002-3 (Disturbance Control Standard) – Contingency Reserve for Recovery from a Balancing Contingency Event, and NPCC Directory # 5 – Reserve.[60] The real-time operating reserve products required are: Ten-Minute Spinning Reserve (or Ten-Minute Synchronized), Ten-Minute Reserve, and Thirty-Minute Operating Reserve. The minimum required amount for each of these operating reserves is determined by the system's first and second largest source-loss contingences, with adjustments for historical non-performance.[61]

  To provide these capabilities as part of the next-day Operating Plan, the ISO: (a) determines the projected operating reserve requirements for each hour of the next Operating Day, (b) assesses the projected supply of each type of reserve for each hour after the Day-Ahead Energy Market scheduling is completed, and (c) if necessary, commits additional resources to meet each hour's projected operating reserve requirements.[62] Presently, these assessments and actions are initially performed as part of the day-before Reserve Adequacy Analysis ("RAA") process, which occurs after the completion of Day-Ahead Energy Market clearing, as described in the Brandien Testimony.[63]

- *Replacement energy.* This capability provides replacement energy, for the balance of the Operating Day, when and as needed, to restore contingency reserve resources to reserve status and to serve an unanticipated increase in demand. In these circumstances, the ISO must dispatch online resources above their day-ahead schedules, or supplementally commit

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The costs of these supplemental commitments are not reflected in the day-ahead prices, and there is no market compensation for these capabilities in the day-ahead timeframe.

[59] *See* Brandien Testimony at 21-22. *See also* ESI White Paper, Section 6.

[60] *See* NERC BAL-002-3 – Disturbance Control Standard – Contingency Reserve for Recovery from a Balancing Contingency Event, Requirement R.1, North American Reliability Corporation, https://www.nerc.com/pa/Stand/Reliability%20Standards%20Complete%20Set/RSCompleteSet.pdf ("NERC-BAL-002-3"); NPCC Regional Reliability Reference Directory # 5 Reserve, Northeast Power Coordinating Council, https://www.npcc.org/Standards/Directories/Directory%205%20-%20Reserve_20200116.pdf ("NPCC Directory 5").

[61] *See* ISO New England Operating Procedures No. 8 – Operating Reserve and Regulation, https://www.iso-ne.com/static-assets/documents/rules_proceds/operating/isone/op8/op8_rto_final.pdf.

[62] *See* Brandien Testimony at 19.

[63] *See id*. at 19-21.

> offline resources without day-ahead schedules, to supply sufficient energy to cover the energy gap through the balance of the day and, if necessary, the next Operating Day. This capability differs from the capability to activate (*i.e.*, commit and dispatch) sufficient real-time operating reserves to respond to a contingency within prescribed limits; instead, replacement energy is needed to restore the system's reserve to a "normal" (*i.e.*, non-energy supplying) reserve state within the prescribed time limits.[64] Specifically, it is the capability necessary for the ISO to (a) replace the energy loss from an initial contingency within ninety minutes, by which time the Ten-Minute Reserve must be restored to reserve status; and (b) if the energy obtained to replace the source loss is from Thirty-Minute Operating Reserve and would result in a deficiency of those reserves beyond four hours, restore the Thirty-Minute Operating Reserve and eliminate the deficiency in that reserve within four hours.
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> At present, in preparing the next-day Operating Plan, the ISO does not normally commit resources, pre-contingency, to ensure the system's Ten-Minute Reserve and Thirty-Minute Reserve can be fully restored within post-contingency restoration timeframes.[65] Therefore, following a major source-loss contingency, during the reserve restoration requirement periods, the ISO may need to commit additional resources, beyond their day-ahead or day-before RAA commitments, to provide the replacement energy and fully restore the system's Operating Reserves.

The specific set of resources, or technologies, and demand quantities the ISO relies on for these essential reliability services to meet the reliability standards described in the Brandien Testimony vary daily. For context, the New England system has over 30 gigawatts ("GW") of capacity resources that supply power, a summer peak demand of approximately 25-26 GW, and net power demand of approximately 21-22 GW during cold weather conditions.[66] Of that capability, the ISO relies upon approximately 4 GW or more to satisfy the three operational requirements discussed above.[67] The resources, or technologies, that are most cost-effective in meeting operational requirements for load-balancing, operating reserve, and replacement energy capability can vary daily, and depend on resource commitments and schedules in the Day-Ahead Energy Market.

While the ISO relies on these capabilities for the essential reliability services they provide, the ISO does not currently compensate resources for them through the Day-Ahead Energy Market.[68] Instead, the ISO relies on unpriced constraints in the Day-Ahead Energy Market unit commitment process to help ensure that there will be sufficient operating reserves each hour of the next day. After the Day-Ahead Energy Market clearing, the ISO relies on out-of-market, uncompensated processes and

[64] *See id*. at 10-17.

[65] *See id*. at 25-26.

[66] *See* ESI White Paper, Section 2.6.3. *See also* Brandien Testimony at 21-23.

[67] *See id*.

[68] *See* ESI White Paper, Section 2.6.1. *See also* Brandien Testimony at 4, 25.

reliability-commitment tools to ensure that there will be sufficient resources to cover the ISO's next-day load forecast and provide replacement energy capability.

As Mr. Brandien states, given the region's growing dependence on just-in-time energy sources and its constrained fuel delivery infrastructure, this current approach for ensuring these operational capabilities is unsustainable.[69] The resources that the ISO is counting on may not have the energy supply arrangements that will enable them to operate upon request on days when they have no reason to expect to run. If the system experiences an unexpected, extended large generation or supply loss during system-stressed conditions (*e.g.*, an extended cold weather period), the region may not have the energy needed to reliably fill the ensuing energy gap. This is particularly true if the loss occurs when renewable resource production capability is low (*e.g.*, the sun is down or the wind is calm).

Therefore, to address these problems, the current market structure needs to procure and provide compensation for the operational capabilities the ISO depends on to ensure a reliable power system, so that resources, regardless of technology type, are incented to invest in additional energy supply arrangements and the technologies that ensure these capabilities remain available to the power system each day.

IV. OVERVIEW OF THE ENERGY SECURITY IMPROVEMENTS AND THEIR EXPECTED IMPACTS

In this section, the ISO describes, at a high level, the Energy Security Improvements and associated market mechanics. The ISO also discusses how the Energy Security Improvements fulfill the directives in the Commission's July 2 Order, and outlines the design's benefits to the region. Finally, the ISO describes the Impact Assessment, which assess the costs and benefits of the Energy Security Improvements.

A. Overview of the Energy Security Improvements

1. The New Day-Ahead Ancillary Services and their Related Market Mechanics

The ISO proposes the Energy Security Improvements to address the identified gaps in the current market and thereby improve energy security for the region in the long-term. As described in the ESI White Paper, these comprehensive market enhancements procure new products (in the form of voluntary ancillary services) in the Day-Ahead Energy Market that will create incentives for energy 'on demand' to manage operational uncertainties each Operating Day.[70]

Specifically, the changes incorporate the ISO's load forecast, currently applied in the RAA process, into the Day-Ahead Energy Market to ensure the market outcomes result in sufficient energy

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[69] *See* Brandien Testimony at 23-26.

[70] *See* ESI White Paper, Section 1.2.

to meet that forecast.[71] This improvement, as further discussed below, is complemented by the payment of the Forecast Energy Requirement Price ("FERP") to all physical resources that clear the Day-Ahead Energy Market and provide the same benefit of meeting forecasted load. The Energy Security Improvements also formalize the three categories of operational capabilities identified above into specific ancillary services, and allow Market Participants to compete to provide those capabilities in the ISO's Day-Ahead Energy Market rather than fulfilling the requirements through uncompensated, out-of-market processes.[72] The Day-Ahead Ancillary Services encompassing these capabilities match the specific operational requirements as follows:

- *Day-Ahead Energy Imbalance Reserve* is a new product that provides a day-ahead means to ensure energy will be available to meet the forecasted load for the next day when that forecast exceeds total physical supply cleared in the Day-Ahead Energy Market.[73] The addition of EIR in the Day-Ahead Energy Market helps prepare the system to meet expected (*i.e.,* forecast) supply and demand conditions during the next Operating Day.

- *Day-Ahead Generation Contingency Reserve* consists of three new products that match the existing real-time operating reserves to provide a day-ahead means to ensure energy reserves – Day-Ahead Ten-Minute Spinning Reserve ("DA TMSR"), Day-Ahead Ten-Minute Non-Spinning Reserve ("DA TMNSR"), and Day-Ahead Thirty-Minute Operating Reserve ("DA TMOR").[74] The addition of GCR in the Day-Ahead Energy Market helps prepare the system to be able to respond to sudden, unanticipated energy supply loss during the Operating Day.

- *Day-Ahead Replacement Energy Reserve* consists of two new products that provide a day-ahead means to ensure replacement energy will be available to restore depleting operating reserves within reliability standards' prescribed timeframes and to address load forecast errors realized during the Operating Day – Day-Ahead Ninety-Minute Reserve ("RER90") and Day-Ahead Four-Hour Reserve ("RER240").[75] The addition of the RER in the Day-Ahead Energy Market helps prepare the system to handle an unanticipated loss of supply,

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[71] *See id*. at Section 6.

[72] Sections 6 through 7 of the ESI White Paper detail each Day-Ahead Ancillary Service product and their impact on Day-Ahead Energy Market prices, including the products' specific rationales, pricing, relation to reliability standards, and numerical examples illustrating market outcomes.

[73] *See* ESI White Paper, Section 6. As further described below, the Energy Security Improvements incorporate the system's forecast load into the expanded day-ahead energy and ancillary services market clearing process. Accordingly, the quantity of EIR to be procured for each hour will be limited to fill the gap (when positive) between the day-ahead forecast load for the hour and the amount of physical energy supply that clears in the Day-Ahead Energy Market. *See id*. at Section 4.2.

[74] *See id*. at Section 7.

[75] *See id*.

> or an increase in demand, that persists for a significant period of time during the Operating Day.

The procurement of these essential reliability services in the Day-Ahead Energy Market ensures the market produces reliable next-day Operating Plans, and compensates suppliers, at transparent competitive prices, for the services the ISO relies on in preparing those plans.[76]

The Energy Security Improvements provide for the ISO to procure and settle the Day-Ahead Ancillary Services as options on energy in real-time to address the misaligned incentives problem.[77] The proposal improves Market Participants' willingness to undertake costly investments in arranging "input" energy sources, even if they might not be used, by providing an opportunity to sell a real option on electrical energy (in amounts and over timeframes that match the operational needs of the power system), as a Day-Ahead Ancillary Service.[78] This settlement design provides Market Participants strong incentives to take real action – *i.e.*, undertake the up-front energy supply arrangement investment – by tying compensation to a strong financial consequence based on the real-time replacement cost of energy.

Mechanically, a Market Participant seeking to sell Day-Ahead Ancillary Services would submit an Option Offer in the same manner as energy offers today.[79] Option Offers to provide the Day-Ahead Ancillary Services are voluntary, but if submitted must be accompanied by a physical resource with a corresponding offer for energy to ensure the cleared capability can be converted into energy in real-time.[80] The design adopts a "single-offer, multiple product" construct: Option Offers are not product specific; instead, to ensure cost-effective outcomes, the co-optimized energy and ancillary services day-ahead clearing process will award option schedules to resources based on their ramping and other physical capabilities.[81] The co-optimization process also ensures that the clearing prices for energy and each ancillary service incorporate the (marginal) suppliers' opportunity costs of foregoing a schedule

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[76] The Energy Security Improvements result in new revenue streams: FERP payments to resources that help meet the new forecast energy requirement constraint, and payments corresponding to Day-Ahead Ancillary Services' obligations.

[77] Section 4 of the ESI White Paper explains the proposed energy option design for the Day-Ahead Ancillary Services, and the settlement mechanics; Section 5, in turn, shows how the energy option design solves the misaligned incentives problem.

[78] *See* ESI White Paper, Section 5.1. This willingness, the paper explains, arises because a Market Participant's valuation of the investment is no longer based on the potential real-time price that it would earn when it has energy supply arrangements, but on the cost that society avoids if it makes the investment (*i.e.*, the replacement cost). *See id*. at Section 5.1.1.

[79] *See id*. at Section 4.6.

[80] *See id*.

[81] *See id*. at Sections 4.1, 4.6.

for a different day-ahead product.[82] Offers that clear day-ahead will be compensated at uniform, transparent, and product-specific market prices resulting from the clearing process.[83]

The Option Offers settlement construct is similar to the existing energy market's two-settlement design: it involves a day-ahead settlement and a real-time settlement.[84] Under this construct, a Market Participant with cleared Option Offers will have both a day-ahead and a real-time settlement for the hours for which it acquires a Day-Ahead Ancillary Services obligation. The Market Participant will receive new day-ahead compensation specific to the corresponding Day-Ahead Ancillary Service obligation to cover its up-front costs of additional supply arrangements, even if it turns out that energy from the resource is not needed for the system to operate reliably the next day.[85] The participant's net settlement will depend on the energy the associated physical resource produces in real-time.

The improvements adopt this approach because it creates strong new incentives for Market Participants selling Day-Ahead Ancillary Services to ensure they have the physical capability (*i.e.*, additional energy supply arrangements) to cover their obligation the next day.[86] A Market Participant with cleared Option Offers to provide Day-Ahead Ancillary Services has a "no excuses" settlement obligation. If the resource does not produce energy in real-time, it will be charged based on the price of real-time energy if that price exceeds the applicable hour's pre-determined strike price. In this regard, the Energy Security Improvements successfully align sellers' private incentives to incur energy supply costs with the expected replacement cost of electricity in real-time (*i.e.*, the cost society avoids).[87]

2. The Energy Security Improvements Meet the Commission's Directives for a Long-Term, Market-Based Solution

The above-described comprehensive, integrated Energy Security Improvements fully comply with the Commission's directives to improve energy security for the region. As the ESI White Paper explains, these interwoven improvements address the existing gaps in the energy market by providing additional incentives, and the compensation necessary, for resources to bolster their energy supply arrangements in a fuel- and technology- neutral manner.[88] They achieve this, more specifically, by:

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[82] *See* ESI White Paper, Sections 4.1, 4.6

[83] *See id*.

[84] *See id*. at Sections 4.3 and 5.1.

[85] *See id*.

[86] *See id*. at Sections 4 and 5.4.

[87] *See* ESI White Paper at Sections 5.1-5.4.

[88] Section 1.3 of the ESI White Paper summarizes how the proposed market design solution addresses the energy security problems facing the region, in full compliance with the Commission's July 2 Order, and the attendant benefits of the market-based solution.

- Procuring the Day-Ahead Ancillary Services that reflect the operational needs of the system, which will formalize, through the Day-Ahead Energy Market, the ISO's option on 3,500 to 5,000 MW of energy reserves each day to help ensure next-day reliable operations. The new services will provide capabilities the ISO currently relies on, but does not compensate for, in the day-ahead timeframe, and ensure that the system is prepared in advance to respond when the region faces the types of real-time stressed system conditions that have created concerns over energy security in the past.

- Providing more accurate and stronger price signals to suppliers during tightening market conditions, including those related to fuel limitations. As briefly discussed in Section II above, for the markets to address energy security concerns and support reliable operations, prices must appropriately reflect tightening, limited supply conditions. Such price signals provide suppliers with commensurately increasing incentives to invest in energy supply arrangements, so they are prepared to perform, if needed, and appropriately compensate them for their flexibility. Having more effective price signals will also provide an early warning that conditions are tightening before an actual scarcity condition.

- Tying compensation to strong financial consequences based on the real-time replacement cost of energy, which can exceed $3,800 per MWh during periods of scarcity, when the resource does not produce energy in real-time.

By sending more accurate price signals on the value of energy and reserve services and strengthening the financial obligation associated with selling these services, as the ESI White Paper explains, the Energy Security Improvements will meaningfully strengthen incentives for participant-driven supply chain-management and reliable energy supply arrangements by resource owners.[89] These incentives are reflected in the Impact Assessment's results, discussed below, which indicate that it is profitable for many resources to maintain greater fuel inventories under the Energy Security Improvement rules, relative to current market rules.[90]

3. Attendant Benefits of the Fully-Market-Based Solution in the Long-Term

In addition to meeting the compliance directive, the Energy Security Improvements maintain New England's transparent, technology-neutral principles of competition, and establish a familiar framework for resources. Specifically, as a fully market-based solution, the Energy Security Improvements also provide the following benefits:[91]

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[89] *See* ESI White Paper, Section 1.3.1.

[90] *See* Impact Assessment, Section IV.

[91] *See* ESI White Paper, Section 1.3.2.

- *Fuel and Technology Neutrality.* To achieve energy security in the *long-term*, as directed by the Commission, the market must incent not just the current fleet, but also the future resource mix, to undertake additional supply arrangements, and pursue the addition of new technologies that will ensure their operational capabilities remain available to the power system each day. Recognizing the evolving resource mix, the Energy Security Improvements focus on promoting reliable electric energy *output* – and are, by design, fuel and technology neutral. The design rewards resources, of any technology or fuel type, that acquire a day-ahead commitment to supply energy or ancillary services and thereby contribute to the system's daily reliability requirements – including renewable resources, traditional and emerging storage technologies, and traditional fossil-fueled generators.[92] In short, these improvements will strengthen the financial incentives for resource owners to undertake more robust energy supply arrangements when cost-effective, while not prescribing what form those supply arrangements may take.

- *Cost Effectiveness.* Providing incentives through the market for electric energy and reserves (again, paying for energy *outputs*, not fuel *inputs*) helps ensure that the Energy Security Improvements address the region's energy security concerns in a cost-effective manner. The improvements provide owners of resources of any type or technology strong incentives to firm-up their fuel or other energy supply sources, through whatever means they find most cost-effective, to support their Day-Ahead Energy Market ancillary services' obligations. By contrast, non-market mechanisms (such as direct subsidies to selected generators to procure additional fuel) benefit only those selected resource owners, providing no incentives to other resources – or to potential new technologies, such as storage – that help comprise cost-effective long-term solutions.

- *Transparency.* Because the new Energy Security Improvements' incentives will be provided through a market-based mechanism, they are signaled through market prices visible to all. In this way, the improvements extend a fundamental benefit of markets – their price transparency. The visibility of the market's strengthened resource incentives will encourage more efficient investments in energy supply arrangements than the current markets – investments that seek to reduce reliability risks in New England's increasingly energy-constrained power system.

- *Consistency with Existing Market Design.* The Energy Security Improvements extend the concepts that underlie the region's longstanding energy markets. The proposed new products and services will work smoothly with the existing day-ahead and real-time markets, filling the gap in the current markets' product suite by providing new

[92] For example, a solar facility with battery storage has the same opportunity to provide these reliability services as a natural gas plant with a contract for LNG or an offshore wind farm that operates at a high capacity factor during the winter.

compensation for resource capabilities not presently compensated in the Day-Ahead Energy Market.

- *Fairness and Innovation.* The Energy Security Improvements compensate all technologies capable of providing energy or any of the new ancillary services, creating a level playing field for Market Participants. As no capable technology is excluded from providing energy or ancillary services, this design should foster innovation, as participants explore the best technologies or other means to capitalize on the new products.

- *Risk-Responsiveness*. Using a market-based approach ensures that the costs of improving the region's energy security correspond to the risks. If the region's energy security risks are not realized in future years – perhaps because they are meaningfully reduced through different policies outside the ISO-administered markets (*e.g.*, through much greater renewable energy production and storage in future years) – then providing the new products and services would have lower revenues for sellers, and procuring them would have lower costs for consumers. This aspect of the design prevents locking consumers into new multi-year obligations that might prove both expensive and unnecessary, as New England's power system continues to evolve.

Additionally, while not specifically related to energy security, the Energy Security Improvements' market-based approach furthers the Commission's goal of price formation.[93] As discussed in Section III of this filing letter, the ISO presently relies on unpriced, out-of-market actions in the energy market to ensure the power system can satisfy NERC, NPCC, and ISO reliability standards and requirements, as the current market design is incomplete. The Energy Security Improvements filed here include well-defined market products with corresponding transparent market-clearing prices. As a result, the Energy Security Improvements ensure that competitive market prices reflect the costs of operating a reliable power system.

Finally, the Energy Security Improvements will help manage the rapid growth of renewables participating in the New England markets in the long-term.[94] As discussed in Section II above, as of April 1, 2019, proposed solar photovoltaic and wind generating facilities comprised more than 76% of the nameplate capacity of proposed new resources in the ISO's interconnection queue. Today, they represent 83%, with approximately 8,6000 MW, including 5,989 MW of offshore wind, scheduled to be on line by June 1, 2024,[95] coincident with the requested implementation date of these improvements. Energy production from these resources is weather-dependent. The Energy Security Improvements'

[93] *See* ESI White Paper, Section 1.3.3. *See also Midwest Indep. Sys. Operator, Inc.*, 170 FERC ¶ 61,075 at PP 32-33 (2020) (citing, *Price Formation in Energy and Ancillary Services Markets Operated by Regional Transmission Organizations and Independent System Operators*, 153 FERC ¶ 61,221 at P 2 (2015)).

[94] *See* ESI White Paper, Section 1.3.3.

[95] https://www.iso-ne.com/system-planning/transmission-planning/interconnection-request-queue. By June 1, 2026, based on interconnection queue proposals, we expect 14,000 MW, including 11,465 MW of offshore wind.

ancillary services will help the system manage the uncertainty over these resources' next-day energy production throughout the year. Further, the improvements will recognize and compensate resources for reliable, flexible, and responsive attributes that help the ISO manage, and prepare for, energy supply uncertainties each day.

B. Expected Impacts of the Energy Security Improvements

To assist the ISO and the New England stakeholders in evaluating the efficacy and cost of the Energy Security Improvements, the ISO engaged the Analysis Group to perform an assessment of the projected impacts of the proposed market rule changes. The Analysis Group met with stakeholders multiple times during a ten-month period to discuss the development of the study assumptions and methodology, the assessment results, and further analysis that the Analysis Group performed in response to stakeholder requests. The results are presented in the Impact Assessment report that is included as Attachment C to this filing.[96] In short, the Impact Assessment shows that the proposed design will create strong financial incentives for resources to maintain more secure energy supplies at a modest cost to consumers when compared to all ISO markets.[97]

1. Overview of the Impact Assessment

As described in Section I of the Impact Assessment, the Analysis Group examined the impacts of the Energy Security Improvements, both quantitatively and qualitatively. The quantitative analysis was performed using a production cost model that simulates New England energy market outcomes. To calculate the expected impact of the Energy Security Improvements under a specific resource mix and market conditions, the production cost model was run twice: once with the Energy Security Improvements in place, and a second time under current market rules (*i.e.*, no Energy Security Improvements). The difference in market outcomes between the two runs of the production cost model—*i.e.*, with and without the Energy Security Improvements—represents the incremental impacts associated with the market rule changes under the assumed resource mix and market conditions.

The quantitative assessment estimated the impact of the Energy Security Improvements across different "cases," which reflect potential future market and system conditions and different levels of stress on the fuel supply systems. While both winter month and non-winter month cases were considered, the quantitative assessment focused on the impacts of the market rule changes during winter months, because energy security currently poses the most pressing challenges to New England in these months. The winter month assessment focused on three cases: a "frequent stressed conditions" case

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[96] In addition to the analysis and tables provided in the Impact Assessment, the ISO and the Analysis Group also shared additional, more granular results from the production cost model with stakeholders. This includes both hourly model output data for the Central Cases, available at https://www.iso-ne.com/static-assets/documents/2020/02/a4_e_preliminary_esi_impact_analysis_hourly_model_outputs.xlsx, and more detailed market and reliability outcome results for a range of scenarios, available at https://www.iso-ne.com/static-assets/documents/2020/02/a4_e_esi_impact_analysis_draft_report_appendix_ii_rev1.pdf.

[97] *See* Impact Assessment, Section I, 6-8.

representing a winter in which multiple, shorter periods of fuel system constraints are experienced, driven in large part by numerous cold-snaps; an "extended stressed conditions" case representing a winter in which one extended period of fuel system constraints are experienced, driven by a single, long cold-snap; and an "infrequent stressed conditions" case from a winter with particularly mild temperatures and no periods of stressed conditions.[98] Section III of the Impact Assessment explains the historical New England winter data used to derive these three "central cases." Load and supply conditions (including resource mix) for the analysis were updated to be more consistent with a future year—December 1, 2025 to November 30, 2026—in which the Energy Security Improvements will be in effect.[99]

Two production cost analyses were also performed for the non-winter months, a "moderate" case, reflecting moderate or typical market conditions, and a "severe" case, reflecting severe conditions with higher energy loads.[100] Between the winter and non-winter cases, the analysis therefore estimated the impacts of the Energy Security Improvements for the entire year.

The production cost model captured key features of the New England markets to provide reasonable measures of the impacts of the proposed market rule changes. The model incorporated both the Day-Ahead Energy Market and the Real-Time Energy Market, the real-time ancillary service markets for ten- and thirty-minute operating reserves, an opportunity cost bidding component that allowed Market Participants to account for limited energy, and, for the model runs that assumed the Energy Security Improvements, the Day-Ahead Ancillary Services that the ISO is proposing.[101] The production cost model simulated market clearing in the Day-Ahead and Real-Time Energy Markets consistent with a competitive wholesale energy market. The model maximized social welfare[102] as reflected in demand bids and supply offers, while satisfying other physical system requirements, including supply-load balancing and procurement of various ancillary services in day-ahead and real-time.[103] Section III of the Impact Assessment provides significant detail regarding the modeling of the day-ahead and real-time markets, including the modeling of the new Day-Ahead Ancillary Services, the modeling of fuel inventory constraints, the treatment of market settlements, and the model outputs.

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[98] *See id*. at Section III, 13-14.

[99] *See id*. at Section III, 14-15.

[100] The results of the assessment for the moderate cases are presented in Section IV.B of the Impact Assessment.

[101] *See* Impact Assessment, Section III.A, 16.

[102] Social welfare in the Day-Ahead Energy Market reflects the sum of bid-in demand net of the sum of supply offers for energy and ancillary services needed to meet all Day-Ahead Energy Market constraints, accounting for any penalty factors associated with failure to meet particular constraints. This welfare calculation is discussed in more detail in the appendix to the Impact Assessment.

[103] *See* Impact Assessment, Section III.A, 16.

The quantitative results of the Impact Assessment are presented largely in terms of the impact that the Energy Security Improvements will have on payments and prices for services provided in the energy markets.[104] Thus, impacts are presented in terms of the change to the market outcomes under the Energy Security Improvements, relative to the current markets, reflecting changes in energy and real-time reserve payments, additional costs incurred and payments received by Market Participants that sell the new Day-Ahead Ancillary Services via energy options, and the additional compensation received by Market Participants for helping to meet the forecast energy requirement in the Day-Ahead Energy Market.

Results are presented in the report for each of the three winter central cases—the two cases that reflect more stressed market and system conditions during winters with "frequent" and "extended" cold spells, and the case that reflects a winter with no stressed market and system conditions due to milder weather[105]—as well as for the two non-winter cases.[106] In addition, the report includes an assessment of several additional "scenarios," which generally start with the winter case analysis and change one or more key assumptions, in order to assess the impacts of the Energy Security Improvements under different assumptions about future market and system conditions.[107] In response to requests from stakeholders, the Impact Assessment also includes scenario analysis with modifications to the Energy Security Improvements design, to provide information on the impacts of alternative designs that were proposed by various participants during stakeholder discussions.[108]

2. The Impact Assessment Results

The results of the Impact Assessment demonstrate how the Energy Security Improvements create strong financial incentives for Market Participants to maintain more secure energy supplies in a manner that will improve the overall reliability of the power system. These incentives are greatest during periods when energy security risks are most severe, thereby creating the strongest price signals when energy needs are greatest. Further, while the strong improvements in energy security will increase costs to consumers, the Impact Assessment demonstrates that those increases come from a market design that lowers overall production costs for the region during more stressed system conditions, a critical indicator that the design enhances the region's energy security in an efficient manner. Section IV of the Impact Assessment provides the detailed study findings.

[104] The results are presented in Section IV of the Impact Assessment.

[105] These results are presented in Section IV.A of the Impact Assessment.

[106] These results are presented in Section IV.B of the Impact Assessment.

[107] These scenarios are summarized in Table 39 and are discussed in Section IV.C of the Impact Assessment.

[108] These scenarios are summarized in Table 40 and are also discussed in Section IV.C of the Impact Assessment.

a. The Energy Security Improvements Provide Strong Incentives to Maintain More Secure Energy Supplies and Improve the Reliability of the Electrical System

The Impact Assessment demonstrates that the Energy Security Improvements create strong financial incentives for resources to maintain more secure energy supplies (*e.g.*, higher levels of energy inventories) and generally improve their ability to deliver energy supplies in real-time, relative to the current market rules, thereby improving the reliability of the electrical system. While the cost of holding additional energy inventory for an extended period of time—*i.e.*, the costs of holding additional fuel in inventory—can be significant,[109] the Energy Security Improvements introduce new revenue streams associated with holding such fuel. The analysis finds, generally, that this additional revenue more than offsets the incremental costs of holding the fuel, indicating that the Energy Security Improvements would be expected to increase energy inventories and improve the region's energy security.

As the Impact Assessment demonstrates, the average incremental payments that Market Participants receive under the Energy Security Improvements far outweigh the additional costs incurred from purchasing and holding additional fuel. More specifically, the additional revenues that oil-fired and dual fuel resources will receive under the Energy Security Improvements from providing energy and ancillary services generally far exceed the increased costs that these Market Participants will incur for holding that fuel in inventory. Thus, for example, while a dual fuel, combined cycle generator will, on average, incur an additional $14 per MW in holding costs during a stressed winter with frequent cold snaps (*i.e.*, "frequent case"), that same resource will on average earn an additional $5,591 per MW from providing energy and ancillary services with the Energy Security Improvements in place.[110] As a result, the net revenues for holding incremental oil under the Energy Security Improvements is $5,577 per MW (equal to the additional revenues of $5,591 less the $14 in holding costs). For an oil-only combustion turbine generator (the New England fleet includes seventy such resources), the results are even more favorable, with holding costs of $134 per MW and additional revenues of $7,591 per MW, yielding an increase in net revenues of $7,385 per MW.[111]

While the magnitude of net revenues varies by case and resource technology type, it remains positive in nearly all cases. Even under infrequent stressed winter conditions, where the net revenues tend to be lowest and the costs highest (because more of the oil remains in the tank at the end of the season), the Impact Assessment shows that the increase in revenues from holding incremental fuel oil

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[109] While the quantitative results in the Impact Assessment focus on how the Energy Security Improvements impact incentives to hold more fuel oil or enter into forward liquefied natural gas contracts for fossil fuel resources to improve availability in real-time, these represent a subset of the actions Market Participants may take in response to the proposed improvements. Other actions that are not quantified in the Impact Assessment include preservation of limited energy inventories (*e.g.*, at hydropower facilities), investments to expand fuel storage capability (*e.g.*, dual fuel), improvements in operational performance (*e.g.*, reduced forced outage rates), and internalization of these new revenue streams in entry and exit decisions.

[110] These results are addressed in Section IV.A.1.c of the Impact Assessment, with the figures presented in Table 11.

[111] *See id*.

under the Energy Security Improvements for the majority of oil-fired resources will outweigh the holding costs.[112] These results therefore unambiguously demonstrate that the Energy Security Improvements would increase the region's fuel oil available for electric generation across a wide range of system conditions, and therefore are likely to improve its energy security.[113]

The Impact Assessment also shows that the Energy Security Improvements would increase incentives for gas-only resources to firm up their energy supply. The analysis specifically considers how the proposal will impact the potential returns from entering into a forward liquefied natural gas contract and finds that the incentives to do so are increased under the Energy Security Improvements.[114] If the Energy Security Improvements incent additional forward liquefied natural gas contracts, natural gas available for electric generation is therefore likely to increase, further improving the region's energy security.

The Impact Assessment also demonstrates that the increased revenues received from the Energy Security Improvements—both FERP payments and returns from energy options—are greatest during periods of high stress, when market conditions are tight and there is a greater need for the energy security that is afforded through the new Day-Ahead Ancillary Services. Using limited gas supplies as a metric for system stress, the assessment finds that FERP, DA TMSR/DA TMNSR, and RER prices are highest when natural gas supplies are limited.[115] Collectively, these results suggest that the payoff from holding fuel inventory (and therefore the incentive to hold fuel inventory) is greatest when the region's gas supply is most constrained—which is the time this incremental fuel will provide the greatest reliability value.

Collectively, these results support the conclusion that the Energy Security Improvements will improve the reliability of the electrical system, particularly during winter periods. As discussed above, the Impact Assessment shows that the incentives provided by the Energy Security Improvements are likely to increase the availability of fuel oil inventories, with these incentives being greatest during periods of tight market conditions when the gas pipeline system is constrained. These results provide insights into ways in which the Energy Security Improvements can reduce stress on fuel systems relied on for energy delivery during periods of tight market conditions, which improves the overall reliability of the electrical system, particularly during winter periods. Further, under scenarios involving loss of significant supply (referred to as "supply shocks"), the Impact Assessment shows that the Energy

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[112] *See id*. at Section IV.A.1.c, Tables 11-13.

[113] As noted above, in addition to conducting this analysis for the ISO's proposed Energy Security Improvements, the Impact Assessment also evaluates these incentives to procure additional fuel oil for a number of alternate designs, including a design in which the RER is removed. Under such an approach, the net revenues from incremental fuel oil continue to be positive in most instances, but are significantly lower. *See id*. at Section V.B.3.d, Tables 62-64. These results suggest that, under such a design, where the RER is eliminated, oil and dual fuel resources would maintain lower inventories of oil than under the ISO's Energy Security Improvements.

[114] *See id*. at Section IV.A.1.d.

[115] *See id*.

Security Improvements can help avoid operating reserve shortages that would otherwise occur under the current market rules.[116] These results are summarized in Section IV.A.7 and Section IV.C.1.b of the Impact Assessment.

b. The Energy Security Improvements Will Lower Production Costs During Stressed Conditions and Improve the Overall Efficiency of the Energy and Ancillary Services Markets During Stressed Conditions

As addressed above, the Impact Assessment utilizes a production cost model to calculate the likely impacts of the Energy Security Improvements. Production costs are a commonly used metric for evaluating the social costs of producing goods and services. Changes in production costs—*i.e.*, the costs that supply-side resources incur to produce energy to meet the New England electricity demand—can signal how proposed wholesale market design changes affect the market's efficiency. If a design proposal lowers production costs, that may signal that the design helps to improve market efficiency, as it indicates that the costs incurred to meet consumer demand have decreased.

The Impact Assessment models the marginal cost of production with the Energy Security Improvements in place as well as those under current market rules.[117] For the scenarios when the Energy Security Improvements are in place, the analysis also considers the incremental cost of holding additional fuel oil that is procured in response to the market rule changes. The Energy Security Improvements' impact on production costs is then calculated as the difference between the total production costs when the proposal is in place and the total production costs under current market rules. This analysis was conducted for each of the three winter central cases.[118]

The Impact Assessment demonstrates that the Energy Security Improvements are expected to lower total production costs during the more severe winter cases, indicating that the costs associated with suppliers procuring more fuel oil under the Energy Security Improvements are more than offset by the costs of producing energy with this additional fuel oil. More specifically, the results show that, under the two more severe winter cases, production costs are reduced by $35.5 million for a winter experiencing frequent severe weather events (the frequent case), and by $19.3 million for a winter experiencing less frequent, but more extended severe weather events (the extended case).[119] These results suggest that the Energy Security Improvements increase market efficiency during periods of

[116] *See* Impact Assessment, Section IV.C.1.b.

[117] These production costs include the fuel and variable costs to produce electricity in real-time.

[118] *See* Impact Assessment, Section IV.A.3, 68-70.

[119] *See id*. at Section IV.A.3, Table 22.

stressed market conditions by incenting the procurement of additional fuel oil that displaces higher-cost generation and meets energy demands at lower cost.[120]

In the case of a milder winter, total production costs under the Energy Security Improvements increase slightly, due to the higher costs of holding fuel inventories until the following winter. Therefore, while modeled production costs decrease by $0.9 million during a mild winter, the incremental holding costs increase by $8.5 million.[121] These results reflect that the Energy Security Improvements function similar to insurance, in that they help to protect against price spikes during tight market conditions, but will have higher costs and limited benefits when conditions are mild and the increased energy inventory incented by the improvements is less likely to displace higher cost energy generation.

c. Change in Customer Payments (Costs) Due to the Energy Security Improvements Will Reflect a Combination of Factors

The Impact Assessment also shows the Energy Security Improvements' expected consequences for payments by load to suppliers and net revenue for resource owners in the energy markets. In the aggregate, the Impact Assessment suggests that the Energy Security Improvements will increase payments by load to suppliers under some conditions and will decrease payments by load to suppliers under other conditions. Specifically, the Impact Assessment finds that aggregate payments by load increase by $132 million (3.2 percent) during a winter with frequent stressed conditions, and decrease by $69 million (-2.5 percent) during a winter with extended stressed conditions. During a milder winter, payments by load increase by $35 million (2.0 percent).[122]

These changes in customer payments reflect a combination of factors.[123] In all three winter central cases, energy prices in the Day-Ahead and Real-Time Markets will decrease (though by varying degrees) due largely to the increase in energy supplies under the Energy Security Improvements and the increase in the supply of energy clearing the Day-Ahead Energy Market. Payments to Market Participants supplying day-ahead energy for contributing to the fulfillment of the forecast energy requirement will offset the decreases in energy prices. Further, payments for Energy Options will also offset the decreases in energy prices, though those offsets are dependent in part on how frequently real-time energy prices rise above the option strike price (which results in a credit to load from suppliers).

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[120] These results are consistent with the Energy Security Improvements introducing new ancillary services that help to address the "misaligned incentives" problem identified in the ESI White Paper, thereby improving market efficiency.

[121] *See* Impact Assessment, Section IV.A.3, Table 22.

[122] These results are reported in Section IV.A.5, Table 25 of the Impact Assessment.

[123] These factors are addressed in Section IV.A.5 of the Impact Assessment, 70-71.

The Impact Assessment also estimates the impact of the Energy Security Improvements on payments by load to suppliers in the non-winter months.[124] It estimates that aggregate payments by load to suppliers will increase by $89 million (3.6 percent) during a moderate non-winter period, and by $125 million (4.6 percent) during a severe non-winter period. When combining the winter and non-winter central cases to get an annualized estimate of costs, the Impact Assessment suggests an annualized increase in payments by load to suppliers associated with the Energy Security Improvements of between $20 million and $257 million per year.[125]

V. DETAILED EXPLANATION OF THE ENERGY SECURITY IMPROVEMENTS AND THE NEPOOL-SUPPORTED ALTERNATIVES

Below, the ISO describes each of the new ancillary services in depth, including the amounts to be procured, and the market mechanics applicable to all energy options offers. Where NEPOOL has adopted an alternative, the ISO describes that alternative as well.

A. New Day-Ahead Ancillary Services

The new Day-Ahead Ancillary Services comprise the Day-Ahead Energy Imbalance Reserve, Day-Ahead Generation Contingency Reserve, and Day-Ahead Replacement Energy Reserve. Each of these essential reliability services, as detailed in the ESI White Paper, corresponds to the operational capabilities that the ISO relies upon, but does not currently compensate, to ensure its next-day Operating Plans have sufficient energy on demand to satisfy NERC, NPCC, and ISO standards and criteria.[126] They each address distinct real-time needs and require different resource capabilities in order to cost-effectively address potential energy gaps that arise on, and persist for, different timeframes. Specifically: EIR provides a day-ahead means to ensure energy in real-time to cover the load-balance gap; GCR provides a day-ahead means to ensure operating reserve energy in real-time in the event of a contingency; and RER provides a day-ahead means to ensure that there is sufficient replacement energy in real-time to restore operating reserves after a contingency and address load forecast errors.

Below, the ISO describes the Day-Ahead Ancillary Services and the corresponding formulaic, system-level requirements (or, more precisely, demand quantities) and physical resource capabilities (above day-ahead energy awards) that will be procured to meet them. As reflected below, the resources, capabilities, demand quantities, and timeframes for each ancillary service match the operational requirements to ensure reliable, and therefore, energy secured, next-day Operating Plans.

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[124] These non-winter periods run from March 1st to November 30th.

[125] *See* Impact Assessment, Section IV.B.4, 82.

[126] *See* ESI White Paper, Sections 6-7. *See also* Brandien Testimony at 27-28.

1. Day-Ahead Energy Imbalance Reserve to Satisfy the Forecast Energy Demand

As addressed in Section 6 of the ESI White Paper, the ISO proposes to procure EIR in the Day-Ahead Energy Market. EIR corresponds to the load-balance reserves discussed in Section III.B of this filing letter, and it is designed to ensure that sufficient energy from physical resources is available to cover load-balance gaps in any hour of the Operating Day through competitive pricing and scheduling in the Day-Ahead Energy Market.[127] This capability contributes to satisfying the Forecast Energy Requirement Demand Quantity, similar to physical energy supply that clears in the Day-Ahead Energy Market.[128] All will receive the FERP.

Pursuant to NERC reliability standards, the ISO must ensure sufficient resources are available to meet forecast energy demand (load) and reserve requirements for each hour of the following Operating Day.[129] The ISO's forecast energy demand (*i.e.*, the expected real-time load, as estimated prior to clearing in the Day-Ahead Energy Market), at times, can exceed the total physical energy supply cleared in the Day-Ahead Energy Market (*i.e.*, Generator Assets, Demand Response Resources, and net scheduled energy imports). Presently, as the Brandien Testimony explains, the ISO ensures reliable operations if there is a gap between forecast energy demand and the cleared day-ahead physical energy supply through supplemental reliability commitments in the RAA process after the Day-Ahead Energy Market clearing.[130] Specifically, as part of the out-of-market RAA process, the ISO applies a forecast energy requirement constraint, and if the total cleared physical energy supply and available fast-start resources are less than the forecast energy demand and reserve requirements, the ISO commits additional resources to meet the constraint.[131] However, the cost of these supplemental commitments is not reflected in the day-ahead prices, and there is no market compensation for these capabilities in the day-ahead timeframe.

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[127] *See* ESI White Paper, Section 6.1.

[128] *See id*. at Sections 6.1-6.2.

[129] *See* Brandien Testimony at 6-7. *See also* NERC-TOP-002-4 – Operations Planning, R.4.

[130] *See* Brandien Testimony at 18-19. The ESI White Paper identifies two situations in which the current energy-only Day-Ahead Energy Market may result in a gap between the total energy cleared from physical supply resources and the system's forecast energy requirement for real-time operations: when total day-ahead cleared energy demand is less that then forecast energy requirement, and if virtual supply offers clear against demand. *See* ESI White Paper, Section 6.1.1.

[131] *See* Brandien Testimony at 19-21. Excess supply capability contributing to satisfying the forecast energy requirement and reserve requirements through the RAA out-of-market commitment process are: non-fast start and non-intermittent resources with day-ahead commitments below their Economic Maximum (*i.e.*, the ramping capability from committed units), fast-start resources available in real-time with or without a day-ahead schedule, and the ISO's forecast of Intermittent Power Resources' real-time generation in excess of their day-ahead schedule. *See id*. at 20.

As Section 6 of the ESI White Paper explains in detail, to ensure the current Operating Plan can meet forecast energy demand throughout the next Operating Day (*i.e.*, in real-time), the ISO proposes to incorporate into the Day-Ahead Energy Market the forecast energy requirement currently used in the uncompensated RAA process, and to procure EIR to satisfy that requirement.[132] Specifically, the Energy Security Improvements incorporate the forecast energy requirement in the Day-Ahead Energy Market as the "Forecast Energy Requirement Demand Quantity," which is equal to ISO's forecast for the total loads in the New England Control Area currently specified prior to the Day-Ahead Energy Market.[133] With the incorporation of that requirement in the Day-Ahead Energy Market, the co-optimized energy and ancillary services Day-Ahead Energy Market clearing process will procure the amount of EIR necessary to satisfy the Day-Ahead Energy Imbalance Service Demand Quantity,[134] which is the difference in a given hour (if positive) between the Forecast Energy Requirement Demand Quantity (*i.e.*, the ISO's expected real-time load forecast for that hour) and the total cleared physical energy supply and the net scheduled interchange (imports minus exports).[135] Resources eligible to satisfy the Day-Ahead Energy Imbalance Reserve Demand Quantity must also have a corresponding day-ahead energy schedule for the same hour, unless the resource has fast-start capability – *i.e.*, ramping capability from day-ahead committed resources and fast-start resources physically located in the New England Control Area.[136]

The energy security benefits achieved by incorporating the forecast energy requirement and procuring EIR to meet that requirement in the Day-Ahead Energy Market are discussed in Section 6.2 of the ESI White Paper. The proposed integration of the forecast energy requirement into the Day-Ahead Energy Market scheduling process will ensure that the sum of all physical supply resources that clear against bid-in demand and any additional EIR will satisfy the system's forecast energy requirement.[137] It ensures the market produces a reliable next-day Operating Plan by providing physical supply not presently cleared or compensated in the Day-Ahead Energy Market, but expected to be needed in real-time to meet demand, with greater incentive to ensure they can perform as planned (*i.e.*, deliver energy in real-time).[138] These market enhancements also have the additional benefit of improving price formation by signaling to the market, through transparent prices, the cost of a reliable next-day Operating Plan.

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[132] *See* ESI White Paper, Sections 6.1.1 and 6.4.

[133] *See id*. at Sections 6.4. The ISO presently develops the forecast for the total loads in New England, and makes that available on the ISO's website pursuant to Section III.1.10.1A(h) of Market Rule 1. The Energy Security Improvements do not modify the existing load forecasting process.

[134] *See id*. at Sections 6.2-6.3.

[135] *See id* at Section 6.4.

[136] *See id*. As noted below, the ISO will further explore import External Transactions' eligibility to provide EIR, and adding that functionality in the Tariff following required coordination with adjacent Balancing Authority Areas.

[137] *See* ESI White Paper, Section 6.2.

[138] *See id*.

2. Day-Ahead Generation Contingency Reserve to Ensure Operating Reserve Energy

As detailed in Section 7 of the ESI White Paper, the ISO proposes to procure GCR in the Day-Ahead Energy Market. GCR comprises three new products that correspond to the real-time operating reserves that the ISO must maintain pursuant to reliability standards, as discussed in Section III.B above.[139] GCR is designed to ensure that this critical reserve capability is procured (as "energy" in reserve) through competitive pricing and scheduling in the Day-Ahead Energy Market.[140] These reserve capabilities contribute to satisfying the demand quantities for DA TMSR, DA TMNSR, and DA TMOR.[141]

Pursuant to NERC, NPCC, and ISO standards and criteria, the ISO must ensure the availability of sufficient resources with physical capability to meet real-time operating reserve requirements.[142] The minimum required amount for each of these reserves is determined by the ISO pursuant to Operating Procedure No. 8, and is based on the system's First Contingency Loss (*i.e.*, "the largest outage (MW) that could result from the loss of a single element," which can be a generator or importing transmission element or resource), and the Second Contingency Loss (*i.e.*, the largest capability outage (MW) that would result from the loss of a single element, after allowing for the First Contingency Loss"), with adjustments for historical reserve non-performance.[143] At present, as Mr. Brandien explains, the ISO ensures these capabilities are met through supplemental commitments as part of the (uncompensated) RAA process, conducted after the Day-Ahead Energy Market clearing.[144] The ISO proposes to procure GCR and to schedule resources' capabilities to meet all three of the real-time operating reserve types through the Day-Ahead Energy Market rather than the RAA process.[145] The GCR comprises three Day-Ahead Ancillary Services products: DA TMSR, DA TMNSR, and DA TMOR.

The ISO proposes to align the GCR requirements for each of the three products with those of real-time operating reserves. To that end, the Energy Security Improvements provide for the procurement of the following GCR-related demand quantities in the Day-Ahead Energy Market: Day-Ahead Ten-Minute Spinning Reserve Demand Quantity, Day-Ahead Total Ten-Minute Reserve

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[139] There are three types of real-time operating reserves: Ten-Minute Reserve Spinning Reserve, Ten-Minute Reserve, and Thirty-Minute Operating Reserve.

[140] *See* ESI White Paper, Section 7.1.

[141] *See id*. at Section 7.2.

[142] *See* Brandien Testimony at 6-7.

[143] *See id*. at 7-10. *See also* Operating Procedure No. 8 at Part III.I.

[144] *See* Brandien Testimony at 19.

[145] *See* ESI White Paper, Section 7.2.

Demand Quantity, and Day-Ahead Total Thirty-Minute Operating Reserve Demand Quantity. As explained in Section 7.2 of the ESI White Paper, the specific amounts for each of these requirements will be determined using the formula currently used for real-time operating reserves. Therefore, the demand quantities will depend on the largest potential energy supply losses, and the timeframes corresponding to the real-time operating reserves. The GCR demand quantities and their corresponding timeframes are illustrated using a conceptual, numerical example in the Brandien Testimony,[146] and specified, based on that example, in Section 7.2 of the ESI White Paper.

Consistent with the real-time operating reserve analogs, the Day-Ahead Ten-Minute Spinning Reserve Demand Quantity can only be satisfied by DA TMSR (*i.e.*, the capability of a resource to either produce additional energy or further reduce energy consumption within ten minutes), but the Day-Ahead Total Ten-Minute Reserve Demand Quantity can be met by a combination of DA TMSR and DA TMNSR (*i.e.*, the capability of a resource to either produce energy or reduce energy consumption within ten minutes).[147] The Day-Ahead Total Thirty-Minute Operating Reserve Demand Quantity can be satisfied by the foregoing or DA TMOR (*i.e.*, the capability of a resource to either produce energy or reduce energy consumption within thirty minutes).[148] To ensure the real-time need can be met, physical resource eligibility to meet the GCR requirements will be based on the existing eligibility and designation rules applicable to real-time operating reserves.[149]

3. Day-Ahead Replacement Energy Reserve to Restore Operating Reserves Within Restoration Time Requirements and Address Load Forecast Errors

a. The ISO's Proposal

As further addressed in Section 7 of the ESI White Paper, the ISO proposes to procure RER in the Day-Ahead Energy Market. RER is designed to serve two functions to ensure a complete, market-based, next-day Operating Plan. First, RER ensures that there is sufficient replacement energy to be able to restore real-time operating reserve within the restoration times prescribed by NERC/NPCC, should a contingency occur in any hour, using competitive pricing and scheduling in the Day-Ahead Energy Market.[150] Second, RER ensures that the market procures the reserve capability necessary to address load forecast errors; RER is structured similar to GCR.[151] The reserve capabilities contribute to satisfying the demand quantities for RER90 and RER240.

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[146] *See* Brandien Testimony at 28-30.

[147] *See* ESI White Paper, Section 7.2.2

[148] *See id*.

[149] *See id*. at Section 7.4. *See also* Tariff at § III.1.7.19.1.

[150] *See* ESI White Paper, Section 7.1.

[151] *See id*.

As explained in Section III.B of this filing letter, NERC and NPCC set forth requirements and criteria for resource capability to be able to activate sufficient operating reserves to respond to a contingency. They also prescribe timeframes for restoring operating reserves after they are converted into energy.[152] Specifically, NERC BAL-002 Requirement R.3 requires the restoration of Contingency Reserves (*i.e.*, Ten-Minute Reserve) to reserve (non-energy producing) status within ninety minutes following the end of a Contingency Event Recovery Period (*i.e.*, fifteen minutes following a Reportable Balancing Contingency Event).[153] NPCC Directory 5 extends this requirement, and requires the restoration of Ten-Minute Reserve within ninety-minutes of becoming deficient.[154] Per NPCC Directory 5, the dispatch of Thirty-Minute Operating Reserve facilitates the restoration of Contingency Reserve/Ten-Minute Reserve. In addition to NERC's restoration requirement, NPCC Directory 5 requires the restoration of Thirty-Minute Operating Reserve within four hours (or 240 minutes) from becoming deficient in those reserves.[155] As the Brandien Testimony illustrates, this means that the ISO must obtain energy to replace the energy supply loss from an initial contingency within ninety minutes, by which time the Ten-Minute Reserve must be restored to its reserve status.[156] Further, if the energy obtained to replace the source loss is from Thirty-Minute Operating Reserve, resulting in a Thirty-Minute Operating Reserve deficiency, the ISO must obtain energy from other resources to restore the Thirty-Minute Operating Reserve and eliminate that deficiency within four hours.[157]

As discussed in Section III.B above, the ISO's current approach does not commit resources (on a pre-contingency basis) to ensure that the system's real-time operating reserves can be fully restored within the post-contingency restoration time requirements. Rather, the ISO assumes that there will be enough supply available from capacity that has no day-ahead award, and will be capable of providing energy to fill the energy gap on the system if, for example, a unit committed day-ahead experiences an unplanned outage or a transmission failure limits a scheduled import of energy. The ISO relies on faster-responding resources to quickly respond to an energy gap created by a sudden large supply loss (*i.e.*, the GCR-type capabilities), and slower-responding resources to restore those operating reserves to reserve status, and to cover the resulting energy gap for the balance of the day.

While the standards establish clear requirements for operating reserve restoration, they do not specify a reserve capability for meeting those requirements. To ensure sufficient replacement energy to restore operating reserves post-contingency consistent with the NERC/NPCC prescribed times, the ISO proposes to define, and procure through the Day-Ahead Energy Market, two new ancillary services

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[152] *See* Brandien Testimony at 11-12.

[153] *See id*.

[154] *See id*.

[155] *See id*. *See also* NPCC Directory 5, R2.

[156] *See* Brandien Testimony at 13-17.

[157] *See id*.

products, corresponding to the specific restoration times: RER90 and RER240.[158] RER90 refers to the capability of a resource to either produce additional energy or further reduce energy consumption within ninety-minutes to satisfy the Ten-Minute Reserve restoration time requirement as part of the next-day Operating Plan. RER240 refers to the capability of a resource to either produce energy or reduce energy consumption within four-hours (or 240 minutes) to satisfy the Thirty-Minute Operating Reserve restoration time requirement as part of the next-day Operating Plan.

Like GCR, the demand quantities for the RER products will be formulaic, based on the sizes of the largest contingencies.[159] The Day-Ahead Total Ninety-Minute Reserve Demand Quantity will reflect the amount needed to restore the Ten-Minute Reserve and the Day-Ahead Total Four-Hour Reserve Demand Quantity will reflect the amount needed to restore the Thirty-Minute Operating Reserve.[160] Resource eligibility to meet these requirements will be consistent with the current real-time operating reserve eligibility and designation rules, similar to GCR. Like real-time operating reserves, the five GCR and RER ancillary services products are one-way substitutes – *i.e.*, a higher product can "cascade down" to help satisfy the less restrictive requirements.[161] As such, resources with GCR capability and RER90 capability would be able to meet the Day-Ahead Total Ninety-Minute Reserve Demand Quantity.[162] Resources with RER240 capability plus the higher reserve capabilities would be able to meet the Day-Ahead Total Four-Hour Reserve Demand Quantity.[163]

Additionally, under the NERC's TOP-002-4, Requirement R.4 the ISO must have Operating Plans for the next day that address, among other things, "expected generation resource commitment and dispatch, interchange scheduling, demand patterns, and capacity and energy reserve requirements." Consistent with this requirement and its Operating Procedures, the ISO develops Operating Plans that provide sufficient reserves to address different events, including load forecast error, which may be realized over the course of the Operating Day. The precise reserve capability and the amount to be used for addressing load forecast errors is currently unspecified. Currently, the ISO relies on real-time operating reserve to help account for load forecast error.[164] These commitments, however, are unpriced and resources are not compensated for this service in the day-ahead timeframe. Furthermore, this

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[158] *See* ESI White Paper, Section 7.2.1

[159] *See id*. at Section 7.2.2.

[160] *See id*. Based on a comparison of the apparent capability to the RER demand quantities, the power system has ample apparent capability to compete to satisfy the RER demand quantities. *See id*. at Section 7.3**.**

[161] *See id*. at Section 7.2.3.

[162] *See* ESI White Paper, Section 7.2.2. The ISO will develop the details regarding claim capability parameters for the ninety-minute and 240-minute products (analogous to Claim10 and Claim30) during the ESI implementation phase, so that they are in place in time for implementation in June 2024.

[163] *See id*.

[164] *See* Brandien Testimony at 10.

approach does not account for slower, more effective resources, which could address these errors with sufficient lead-time.[165]

As part of this effort, the ISO proposes to address load forecast errors through the Day-Ahead Energy Market. Specifically, the ISO proposes to apply RER to support the system's needs for reserves to address these errors that may be realized during the Operating Day.[166] To achieve this, the proposed rules filed here incorporate in the RER demand quantities an allowance for load forecast error. Consistent with the current practice, the detailed calculation for determining the amount will be developed with stakeholders and specified in the ISO's Operating Procedures, where the amounts for all real-time operating reserve requirements are specified presently. With this capability, the Day-Ahead Energy Market outcomes will ensure reliable next-day Operating Plans that account for load forecast errors that may be realized during the Operating Day within the RER90 and RER240 response timeframes.

b. The NEPOOL-Supported Alternative

NEPOOL voted in support of an alternative to the ISO's proposed RER design. The NEPOOL-supported alternative amends the ISO's proposed RER provisions in two distinct ways, reflecting the amendment advocates' position that the RER is unnecessary and costly.[167] First, the NEPOOL alternative provides for the ISO to calculate the RER quantity and resulting costs only for the three winter months of December through February. To effectuate this outcome, the NEPOOL alternative sets the RER quantity to zero during the nine non-winter months.[168] Second, the NEPOOL-supported proposal removes from the RER requirements the language that would authorize the ISO to increase the RER amount in case its load forecast is in error. To accomplish this change, NEPOOL's proposal removes the ISO-proposed authorizing language altogether.[169]

The ISO does not support these alternatives. As explained above, the RER is a market-based methodology to ensure the operational capabilities the ISO presently relies on to meet the reliability standards' restoration requirements, and its costs will be transparently reflected in the market. Formalizing the RER in the Day-Ahead Energy Market is consistent with the Commission's directive, and the ISO's objective, to transparently price, through the markets, the costs of operating a reliable power system in accordance with reliability needs of the power system.[170] As noted, the ISO is currently

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[165] *See* ESI White Paper, Section 7.2.1.

[166] *See id*. at Section 7.1.

[167] *See* New England States Committee on Electricity Presentation to NEPOOL Markets Committee, *ESI Design* at 10-15 (Apr. 2, 2020), http://nepool.com/uploads/NPC_20200402_Composite4.pdf ("NESCOE Presentation").

[168] The NEPOOL-supported change is reflected in Attachments E-1 and E-2, Tariff at §§ 1.8.5(d)-(e).

[169] The NEPOOL-supported change is reflected in Attachments E-1 and E-2, Tariff at §§ 1.8.5(d)-(e).

[170] *See* July 2 Order at PP 53-54 (reaffirming "support for market solutions as the most efficient means to provide reliable electric service to New England consumers at just and reasonable rates"). *See also* December 3 Order at P 96

counting on, but failing to compensate, resources for these capabilities, which contributes to the fundamental energy security "misalignment" problem.

Further, limiting the procurement of RER to winter months fails to recognize that the underlying NERC and NPCC standards supporting these capabilities apply throughout the year, and that the ISO's ability to meet them may grow more uncertain in non-winter months as the power system evolves to include more just-in-time energy sources. Moreover, as indicated above, the design is risk responsive, and costs will reflect the relative energy security risks faced by the system; if those risks are lower in non-winter months, consumer costs will fluctuate accordingly. Finally, the reliability standards require accounting for demand patterns and the use of reserves for load forecast errors. The ISO's proposal formalizes in the market the operational capabilities relied on to address unanticipated demand pattern changes.

B. Market Mechanics Applicable to All Day-Ahead Ancillary Services

Below, the ISO describes market mechanisms applicable to all energy options to provide the Day-Ahead Ancillary Services' products.

1. Day-Ahead Ancillary Services as Energy Options

As discussed in Section III of this filing letter, Market Participants facing resource production uncertainty may have inefficiently low incentives to invest proactively in additional energy supply arrangements, for those arrangements entail upfront costs and the current market design does not compensate them commensurate with the social benefits gained from those arrangements. This incentives misalignment, in turn, can have adverse reliability consequences as the ISO is relying on those resources' uncommitted day-ahead capabilities in its next-day Operating Plans to prepare for, and manage, uncertainties. The remedy for this problem, as indicated in the ESI White Paper, is to establish an incentive for Market Participants to incur such up-front costs.[171] Accordingly, the central objective of the Day-Ahead Ancillary Services' construct is to incent Market Participants to take real actions – in this case, incurring up-front costs of arranging additional energy supply in advance of the Operating Day – so that they have the ability to produce energy if called to operate.

As Sections 4 and 5 of the ESI White Paper explain, the ISO's proposal achieves that objective by expanding the Day-Ahead Energy Market to procure new Day-Ahead Ancillary Services that provide Market Participants new revenue streams by which they can profit from improved energy

(stating, "We agree with the dissent that the value of these resources must be accurately reflected in the market in order to address fuel security issues in the long-term. Moving to a market-based approach as soon as possible is the best way to achieve that objective.").

[171] *See* ESI White Paper, Section 5.1 (explaining that to solve the misaligned incentives problem the market needs to (1) compensate suppliers sufficiently so that they are willing to incur the up-front cost of arranging energy supplies, when cost-effective from society's standpoint, and (2) tie that compensation to whether or not the supplier's resource provides energy).

supply arrangements, and settling those services as real options on energy.[172] As more fully discussed below, the ISO proposes to implement this design using a standardized, uniform offer for all Day-Ahead Ancillary Services.[173]

Under the proposed design, a Market Participant seeking to sell Day-Ahead Ancillary Services would submit a *single* Option Offer –specifying the minimum price that it is willing to be paid to accept the obligation. A Market Participant with a cleared Option Offer (and thus, Day-Ahead Ancillary Services obligation) would receive both a day-ahead and a real-time settlement for the hours for which it acquired the obligation. The Market Participant would receive a day-ahead up-front payment corresponding to the Day-Ahead Ancillary Service for which the Option Offer cleared, and would be subject to a corresponding closeout charge (or cost) in real-time. The closeout charge is equal to the difference between the real-time price for energy and a pre-determined option strike price if the real-time price is greater than the strike price. Otherwise, the closeout charge is zero. The Market Participant's net settlement depends on the energy the physical resource associated with the cleared Option Offer produces in real-time.

While the proposed option settlement method for the Day-Ahead Ancillary Service differs from the day-ahead reserve constructs in other regions,[174] it is the appropriate approach to address New England's unique energy security concerns because it creates stronger incentives for Market Participants to invest in energy supply arrangements – *i.e.*, to be able to cover their Day-Ahead Ancillary Service obligations – than other approaches.[175] As the White Paper explains, when day-ahead obligations for reliability services are settled against the real-time reserve price (as is the case under other approaches), rather than against the energy price as proposed here, the Market Participants selling the service do not fully internalize the high-price for energy that society pays if fuel is scarce and a resource is unable to operate when needed.[176] A real-time reserve deviations settlement design does not solve the misaligned incentives problem that exists in New England's existing market construct.

Conversely, settling Day-Ahead Ancillary Services as options on energy fundamentally changes the incentives present in the existing New England market construct today.[177] This construct compensates Market Participants sufficiently so that they will be willing to incur the up-front costs of arranging the energy supply in advance, whenever that would be cost-effective from the system's standpoint, and ties financial consequences (*i.e.*, the replacement cost) for failure to deliver to the price

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[172] *See* ESI White Paper, Sections 4.3, 5.1 and 5.2.

[173] *See id*. at Sections 4.2 and 4.6.

[174] *See, e.g., New York Indep. Sys. Operator, Inc.*, 151 FERC ¶ 61,057 (2015).

[175] *See* ESI White Paper, Section 5.4.

[176] *See id*.

[177] *See id*. at Sections 4.3 and 5.

of energy in real-time.[178] Under the proposed approach, as the paper explains, a Market Participant's willingness to undertake the up-front investment is no longer based solely on the real-time energy price that it would earn if it arranges energy supplies, as is the case under the current market design, but also on the real-time energy price that society avoids if the participant makes the arrangement.[179] Selling the option allows the Market Participant to internalize, in its option offer price, the high costs that may prevail if it cannot operate when its resource is in demand.[180] The real-options settlement design aligns a Market Participant's incentives to invest in energy supply arrangements with the replacement cost that society would incur, at the margin, if it fails to do so, resolving the misaligned incentives problem.[181]

2. Energy Option Offers

a. Option Requirements

The Option Offer specifics are discussed in detailed in Section 4 of the ESI White Paper. As briefly noted above, to provide Day-Ahead Ancillary Services, a Market Participant would submit an Option Offer – a newly created offer form. Option Offers are not specific to a type of Day-Ahead Ancillary Service product. Under the proposal's "one offer, multiple product" construct, the clearing process, which is further described below, will substitute Option Offers to meet any Day-Ahead Ancillary Service requirement. In the Day-Ahead Energy Market clearing process, the participant's offer may clear for EIR, GCR, or RER.

Option Offers are voluntary.[182] As the ESI White Paper explains in Section 4.2, this non-compulsory construct is appropriate, as it enables Market Participants to offer into the Day-Ahead Energy Market based on their expected profitability. Market Participants may choose to offer both energy and Day-Ahead Ancillary Services, and the expanded, co-optimized Day-Ahead Energy Market clearing process will select the most valuable assignment of offers to award, so as not to award multiple obligations to the same megawatt of energy capability in the same delivery hour.[183]

While Option Offers are voluntary, if submitted, they must meet certain requirements, the specifics of which are discussed in the ESI White Paper, Section 4.6. First, consistent with the underlying product – *i.e.*, delivery of energy in real-time – Option Offers must be associated with a resource registered as a Generator Asset or a Demand Response Resource with a corresponding Supply Offer or Demand Reduction Offer in the Day-Ahead Energy Market for the same hour of the Operating

[178] *See id*. at Sections 5.1 and 5.2.

[179] *See id*.

[180] *See* ESI White Paper, Section 5.2.

[181] *See id*.

[182] *See* Tariff at § 1.3.1(c).

[183] *See* ESI White Paper, Section 4.2.

Day.[184] As noted earlier, the Day-Ahead Energy Market clearing process is based on a resource's operating characteristics (*e.g.*, ramp rates, startup lead times, maximum output levels). This ensures Option Offer schedules do not exceed the resource's capability to deliver the underlying product.[185] It also enables Market Participants to physically deliver real-time energy, in amounts and with lead-times corresponding to their particular Day-Ahead Ancillary Service awards.

Second, like energy offers today, Option Offers are hourly offers with a corresponding offer price and offer quantity. Specifically, the offers must stipulate: (i) the applicable hour of the Operating Day; (ii) an offer price (MWh/$) that is greater than or equal to zero; and (iii) an offer quantity (in MWh) that is greater than or equal to zero, but does not exceed the corresponding physical resource's Economic Maximum Limit or Maximum Reduction.[186] Market Participants may submit different Option Offer prices and quantities for each hour.

The proposal caps the Option Offer price at the Reserve Constraint Penalty Factor ("RCPF") corresponding to the Forecast Energy Requirement Demand Quantity, which the ISO proposes to set at 101% of the sum of all the penalty factors corresponding to the GCR and RER requirements. As the ESI White Paper explains, this restriction is non-substantive as any Option Offer higher than that value would be pointless, as it would not clear in the Day-Ahead Energy Market.[187] As noted, the capability of the physical resource associated with the Option Offer will determine how much of an offer can be counted towards meeting each particular service requirement; a Market Participant will not be awarded an energy option that is greater than the lower of its maximum eligible capability and its maximum offered amount.

Finally, to facilitate the co-optimization of energy and ancillary services in the expanded Day-Ahead Energy Market, the ISO's proposal provides for Option Offers to be submitted by the deadline for submitting day-ahead energy offers – *i.e.*, no later than 10:00 a.m. on the day before the Operating Day. Option Offers are not standing offers; they will not remain in effect for subsequent Operating Days.[188]

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[184] For clarity, storage facilities registered as Generator Assets are expressly able to submit Option Offers. *See* Tariff at § III.1.10.6.

[185] *See* ESI White Paper, Section 4.2.

[186] *See id*. at Section 4.6.

[187] *See id*.

[188] *See id*.

b. Option Strike Price

i. The ISO's Proposal

Day-Ahead Ancillary Services obligations assigned to Option Offers that clear in the market will be settled as options on real-time energy. As the White Paper explains, energy option settlement involves three elements: (1) a sale of the option, which occurs at the option price (*i.e.*, the clearing price, which is discussed later); (2) a pre-determined strike price; and (3) the real-time price of the good the seller is providing an option on (*i.e.*, the real-time price for energy, as discussed earlier).[189] The basis for the strike price, the strike price-setting guidelines, and the ISO's proposed approach for determining the strike price are discussed in Section 4.5 of the ESI White Paper. The potential impacts of the strike price on economic incentives are addressed in Section 5.3.

As Section 4.5 explains, a Market Participant's closeout is a function of the Option Strike Price. Setting the appropriate strike price is a fundamental aspect of the proposal given its impact on suppliers' incentives to, in this case, undertake additional energy supply arrangements.[190] To establish the appropriate Option Strike Price, the ISO considered three aspects that guide strike price determination, which provide for the strike price to be: (1) known before the offer is due; (2) set at the expected value of the underlying good (*i.e.*, "at the money"); and (3) close enough. According to these guidelines, which are discussed in detailed in Section 4.5 of the paper, setting the strike price at approximately the expected value of the underlying good ensures the most efficient outcomes, but it does not need to be precise: a strike price that is set a bit above the "at the money" level does not change incentives materially; a strike price that is set far above the "at the money" level can dramatically undermine incentives and compromise the benefits of the design.

Sections 4.5 and 5.3 of the ESI White Paper explain the trade-offs of setting the strike price too high or too low, and provide the basis for the ISO's proposed Option Strike Price and the methodology for setting its value. As explained therein, if the strike price is set too high, then suppliers with a Day-Ahead Ancillary Service obligation face no risk of having to incur the cost of replacing the energy in real-time settlement if they do not perform.[191] The absence of financial consequences diminishes Market Participants' private investments. Thus, the incentives for suppliers to invest in arranging supplies in advance would not be changed from today's market design, and the misaligned incentives problem would remain unresolved. If the strike price is set too low, then the option settlement construct would be no different than today's day-ahead forward sale of energy.[192] To avoid diluting a Market Participant seller's incentives for cost-effective energy supply arrangements, Sections 4.5 and 5.3 explain that the strike price should be set at or below the seller's marginal cost of energy in real-time.

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[189] *See id*. at Section 4.5.

[190] *See* ESI White Paper, Sections 4.5 and 5.3.

[191] *See id*.

[192] *See id*.

Accordingly, to provide efficient incentives, the ISO proposes to set the Option Strike Price as the expected value of the real-time energy price for the corresponding delivery hour.[193] Setting the Option Strike Price at this value provides a transparent, uniform, strike price at or below the ancillary service resource's marginal cost without undermining seller's incentives.[194] Conversely, a strike price that is set higher than the expected real-time energy price will tend to mute incentives to invest in energy supply arrangements, undermining the performance of the expanded energy and ancillary services Day-Ahead Energy Market design.[195]

Consistent with the strike price-setting guidelines, the ISO proposes to calculate and post the Option Strike Price prior to each day's submission of the deadline for the Day-Ahead Energy Market. Accordingly, the strike price will be the *forecasted* expected real-time Locational Marginal Price for the system.[196] As expected real-time prices vary from hour-to-hour and from day-to-day, the strike price will vary each hour of the Operating Day. Moreover, because Option Offers will settle using the Real-Time Hub Price, as discussed below, the ISO's forecast process for the Option Strike Price will also use the expected Real-Time Hub Price.[197] For transparency, the forecast used to determine the Option Strike Price will be based on a publicly-available forecasting algorithm, and the ISO will review any potential revisions to the forecasting process and algorithm, prospectively, through the stakeholder process.

ii. The NEPOOL-Alternative Proposal

NEPOOL supported an alternative to the ISO's Option Strike Price proposal. The NEPOOL-approved alternative proposal revises the ISO's proposal by adding $10/MWh to the strike price in all hours.[198] According to advocates of this NEPOOL-approved change, this proposal would reduce the cost and risk of the energy call option for providers.[199]

As discussed above, the ISO's proposed energy options design provides for the ISO to set an Option Strike Price for each hour. As Section 5.3 of the ESI White Paper explains, the financial incentives for a resource that sells Day-Ahead Ancillary Services to procure fuel (or otherwise take actions to be available to provide real-time energy) can decrease when the strike price exceeds the resource's marginal costs of producing energy. Accordingly, as explained therein, the ISO proposes to

[193] *See id*. at 4.5.

[194] *See id*.

[195] *See* ESI White Paper, Sections 4.5 and 5.3.

[196] *See id*. at Section 4.5.

[197] *See id*. Section 4.3.

[198] The NEPOOL-supported change is reflected in Attachments E-1 and E-2, Tariff at § 1.8.3.

[199] *See* NESCOE Presentation at 6-8.

set the Option Strike Price at a forecast of the Real-Time Hub Price. The proposed adder to the ISO's proposed Option Strike Price, while potentially lowering costs to load, can also reduce incentives for resources that sell Day-Ahead Ancillary Services to undertake energy supply arrangements by reducing the closeout costs if they do not procure fuel. This reduction in incentives appears to be most severe during periods when the system is stressed, suggesting that such an adder will undermine the design's objectives most significantly when energy security is most critical to the region. As a result, the proposed strike price adder would undermine the design's efficacy in addressing the misaligned incentives problem and potentially reduce the design's ability to address the region's energy security concerns. Based on these observations, the ISO does not support the alternative proposal.

3. Option Offers Clearing Basics, Prices and Penalty Factors

a. Clearing Basics

To procure Day-Ahead Ancillary Services cost-effectively, the ISO proposes to co-optimize (*i.e.*, simultaneously-clear) the Day-Ahead Ancillary Services with all energy supply offers and demand bids in the Day-Ahead Energy Market.[200] Specifically, the Day-Ahead Energy Market clearing (or scheduling) process will jointly optimize all offers and bids to ensure each energy and ancillary service requirement is met. This includes: (1) Demand Bids, Decrement Bids, Demand Reduction Offers, Supply Offers, Increment Offers, and External Transactions for energy; (2) Option Offers to satisfy the Day-Ahead Ancillary Services' six demand quantities (*i.e.*, the EIR, GCR, and RER requirements); and (3) Supply Offers, Demand Reduction Offers, External Transactions, and Energy Call Option Offers to satisfy the Forecast Energy Requirement Demand Quantity. The energy and ancillary services co-optimization in day-ahead enables the market-clearing process to determine the most cost-effective assignment of resource offers for all Day-Ahead Energy Market products.

Consistent with the underlying real-time need, the clearing process will only count physical resources located in New England toward the Day-Ahead Ancillary Services' requirements.[201] Additionally, for GCR and RER, the physical resource corresponding to the Option Offer must also meet the eligibility requirements for real-time operating reserves, which are set forth in Section III.1.7.9.1 of the Tariff.[202] For EIR, the Option Offers also must be associated with a physical resource

[200] In the context of EIR, *see* ESI White Paper, Sections 6.2-6.2; for GCR and RER, *see id*, at Section 7.2.3.

[201] At present, External Resources/Transactions are not eligible to provide real-time operating reserves, and the proposal maintains that construct. *See* Tariff, at § III.1.7.19.1. The ISO will further explore import External Transactions' eligibility to provide EIR, and adding that functionality in the Tariff following required coordination with adjacent Balancing Authority Areas. Although the proposal does not provide for these resources to be counted toward satisfying the EIR Day-Ahead Ancillary Services' requirements, day-ahead cleared imports would be eligible to receive FERP payments as compensation for helping meet the forecast energy requirement.

[202] *See* ESI White Paper, Section 7.4.

with either an energy day-ahead commitment for the same hour, or a physical resource with fast-start capability.[203]

b. Clearing Prices

The ISO will calculate the clearing prices based on the co-optimization of energy and ancillary services, given the set of energy offers and bids, and the forecast energy and ancillary services requirements. The resulting clearing prices will reflect the cost of meeting the specific requirements, accounting for both the marginal offer price and the suppliers' opportunity costs of not providing energy or any other ancillary service product for the same hour. Consequently, whenever the inter-product opportunity costs are non-zero, as determined in the clearing process, the day-ahead prices for energy will commonly incorporate the clearing prices for the Day-Ahead Ancillary Services as well. In addition to the day-ahead prices for energy, for each hour of the Operating Day, the multi-product Day-Ahead Energy Market clearing process will also produce a clearing price for the EIR, each GCR product, and each RER product.

As Section 6.2 of the ESI White Paper explains, the addition of the forecast energy requirement in the Day-Ahead Energy Market results in both the current bid-in energy demand curve and a new forecast energy requirement quantity for energy.[204] Consistent with standard pricing principles, as the ESI White Paper further explains,[205] this will result in two separate prices (*i.e.*, the day-ahead price for energy and a new FERP), with each price reflecting the system's incremental cost, including the marginal resource's opportunity cost, if present, of satisfying the bid-in demand curve and the forecast energy requirement quantity at the margin.[206] The FERP will be calculated as the marginal cost to satisfy the next increment of the Forecast Energy Requirement Demand Quantity, and will be assigned as the clearing price for the EIR.[207] That marginal cost, as the ESI White Paper explains in Section 6.2, will reflect either: (1) the (marginal) savings from supplying day-ahead energy in terms of the avoided cost of an energy option to meet the forecast energy requirement constraint or (2) the (marginal) cost from supplying additional day-ahead energy (*i.e.*, the difference between marginal supply and demand

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[203] *See id*. at Section 6.4.

[204] *See id*.

[205] *See id*. Therein, the paper references the "marginal-cost pricing principle," which sets compensation based on the marginal cost of providing the service; in this case, EIR or energy supply.

[206] *See id*.

[207] *See* ESI White Paper, Sections 6.2-6.3. While the clearing price for EIR is the same value as the FERP, the proposed Energy Security Improvement Tariff rules treat these as two separate prices because each are paid to different cleared quantities and products. As Section 6.2 of the ESI White Paper explains, and as further discussed in the settlement section below, the FERP is paid to cleared physical energy supply, while the EIR clearing price (which is equal to the FERP) is paid to Option Offers cleared for EIR; both cleared physical energy supply and EIR awards contribute to satisfying the Forecast Energy Requirement Demand Quantity.

offers) if cleared day-ahead energy exactly meets the forecast load. At this price, a Market Participant would be no worse off supplying day-ahead energy as compared to supplying EIR.[208]

Because of the product substitutability structure of the GCR and RER ancillary services products, clearing prices for the ancillary services with shorter response times will be equal to or greater than the clearing prices for the products with longer response times. This price cascading property is explained in Section 7.2.3 of the ESI White Paper. Specifically, clearing prices for the respective reserve products comprising GCR and RER will be based on the shadow price (*i.e.*, the change in the system cost if the demand quantity was incrementally higher) associated with each constraint.[209] To ensure that each GCR and RER product is compensated for the marginal value it provides by satisfying multiple constraints, the clearing price for each product will be set as the sum of the shadow prices (*i.e.*, the sum of the marginal costs) for each constraint to which it contributes, as illustrated in Section 7.2.3 of the paper. Thus, similar to real-time operating reserves, excess capability may "cascade" down from higher quality products to the lower quality products to fulfill the respective requirements. Conversely, the clearing prices for GCR and RER may "cascade" up (*i.e.*, incorporate the clearing price of reserve lower down the hierarchy).[210]

The clearing prices are expected to vary hourly in the day-ahead, as supply and demand dictate. In this regard, they serve to reward resources that are the most cost-effective suppliers of each product on any given day. While the predominant resource for satisfying the system's load-balance and replacement energy needs may be a combined-cycle generator today, with time, as new storage-based technologies become more prevalent, the most cost-effective resource to satisfy the same operational requirements may be one that uses those technologies.

c. Reserve Constraint Penalty Factors

The ISO also proposes to use RCPFs to set the clearing prices when there are insufficient energy offers or Option Offers to satisfy the forecast energy and ancillary services demand quantities. The RCPFs are "cost caps" intended to enable the system to meet the requirements. They reflect the maximum redispatch cost to meet those requirements and set the clearing prices in a shortage.

The ISO proposes to set the RCPFs for the GCR requirements at the same value of the RCPFs for their real-time analog.[211] The RCPFs for each real-time reserve requirement are specified in Section III.2.7A(c) of the Tariff. Specifically, the ISO proposes to set the RCPF for: (1) Day-Ahead Ten-Minute Spinning Reserve Demand Quantity at the RCPF for the Real-Time Ten-Minute Spinning Reserve

[208] *See id*.

[209] *See id*. at Section 7.2.3.

[210] The Commission has previously recognized these cascading principles, and they are consistent with the real-time reserves pricing construct. *See* Remedying Undue Discrimination through Open Access Transmission Service and Standard Electricity Market Design, 67 Fed. Reg. 55451 (FERC proposed Aug. 29, 2002).

[211] *See* ESI White Paper, Section 7.4

Requirement, which is $50/MWh; (2) Day-Ahead Total Ten-Minute Reserve Demand Quantity at the RCPF for the Real-Time Ten-Minute Reserve Requirement, which is $1,500/MWh; and (3) Day-Ahead Total Thirty-Minute Operating Reserve Demand Quantity at the RCPF for the Real-Time Minimum Total Reserve Requirement, which is $1,000/MWh.[212] This ensures pricing consistency if one of the reserve capabilities is in shortage in both the day-ahead and real-time markets.[213]

The ISO proposes to set the RCPFs for the RER Total Ninety-Minute Reserve Demand Quantity at $250/MWh, and for the RER Total Four-Hour Reserve Demand Quantity at $100/MWh.[214] The RCPF for the RER ninety-minute requirement of $250/MWh is based on the current RCPF for the replacement reserve requirement. The replacement reserve requirement was incorporated into the Real-Time Energy Market, in part, to address similar concerns as the RER ninety-minute requirement.[215] As the ESI White Paper explains, simulation analysis performed at that time showed that $250/MWh is a reasonable guide to the maximum re-dispatch cost for incremental reserve amounts above the Total Thirty-Minute Requirement. In practice, violations of the replacement reserve of the thirty-minute requirement in real-time have been infrequent events. Based on that, the ISO proposes to apply the same RCPF for the RER ninety-minute requirement.

The rationale for the proposed RCPF for the Total Four-Hour Reserve Demand Quantity of $100/MWh is provided in Section 7.4 of the ESI White Paper. As explained therein, the proposed value was determined using the model developed for the Impact Assessment to evaluate the maximum re-dispatch cost that would be incurred to enable that model to co-optimize the Day-Ahead Energy Market to satisfy the RER four-hour requirement.[216] The Impact Assessment results are summarized in Table 14 included therein. That analysis showed that the system, as modeled, was able to satisfy the full four-hour requirement between 98% and 100% of the time. Based on the analysis results, the proposed value should enable the system to meet the requirement in almost all but the most extreme, rare situations. The ISO will review and refine this value, if appropriate, after it gains more experience with the co-optimized day-ahead energy and ancillary services design.

The ISO does not propose a separate RCPF for the Day-Ahead Energy Imbalance Reserve Demand Quantity, because the maximum cost cap for that is addressed through the RCPF for the Forecast Energy Requirement Demand Quantity, which the ISO proposes to set at 101% of the sum of all day-ahead RCPFs (*i.e.*, $2,929/MWh). Section 6.4 of the ESI White Paper provides the basis for the Forecast Energy Requirement Demand Quantity RCPF. As explained therein, the forecast energy requirement results in the Day-Ahead Energy Market procuring EIR to satisfy the expected real-time load in New England during the applicable hour of the next day, and therefore, must be prioritized over

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[212] *See id*.

[213] *See id*.

[214] *See id*.

[215] *See* Replacement Reserve Order, Docket ER13-1736-000.

[216] *See* ESI White Paper, Section 7.4.

all other Day-Ahead Ancillary Services. Establishing the RCPF for the Forecast Energy Requirement Demand Quantity at the proposed value enables the co-optimized Day-Ahead Energy Market clearing process to clear offers to satisfy the forecast energy requirement first before satisfying other ancillary service requirements when there are insufficient offers for energy and Option Offers to meet simultaneously the forecast energy requirement and all ancillary services requirements. To achieve this, mechanically, the RCPF for the Forecast Energy Requirement Demand Quantity must be set at a value greater than the *sum* of all the RCPFs for all the other Day-Ahead Ancillary Service demand quantities.

4. Settlement of Day-Ahead Ancillary Services Obligations

a. Obligations

Under the ISO's proposal, each Market Participant with an Option Offer that clears in the Day-Ahead Energy Market (*i.e.*, receives an award/schedule) will receive a Day-Ahead Ancillary Service obligation corresponding to the specific demand quantity(ies) toward which the participant's resource is being counted, and will be paid the clearing price associated with that obligation, as further explained below.[217]

As discussed above, the Day-Ahead Ancillary Services design is a physical-delivery market. Similar to physical-delivery markets, as explained in Section 4.4 of the ESI White Paper, the sole consequence of non-performance following the award of a Day-Ahead Ancillary Service obligation is a net settlement charge based on the price of real-time energy when that price exceeds the Option Strike Price. This settlement rule aligns sellers' private incentives to incur energy supply costs with the expected replacement cost of electric energy in real-time, consistent with the design's objectives.

b. Settlement Terms

The settlement terms applicable to cleared Option Offers are discussed in detail in Section 4.3 of the ESI White paper. As explained therein, Day-Ahead Ancillary Services obligations will be settled as real options on energy, consistent with their value as a call option on the physical resource's energy in real-time. The same settlement treatment will apply to all Option Offers that receive a Day-Ahead Ancillary Service obligation, regardless of the specific service requirement satisfied by the Option Offer or the clearing price paid for the option.

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[217] Consistent with the "participation payment principle," which is addressed in Section 6.2 of the ESI White Paper, if the physical resource contributes toward satisfying more than one requirement, whether the Forecast Energy Requirement Demand Quantity or Day-Ahead Ancillary Services demand quantities, the participant will be paid the shadow price of each constraint to which its resource contributes. For example, a Market Participant with a Day-Ahead Ancillary Service Obligation corresponding to Day-Ahead Ten-Minute Spinning Reserve capability would be contributing to satisfying not only the Day-Ahead Ten-Minute Spinning Reserve Demand Quantity, but also the subordinate demand quantities (*i.e.*, Day-Ahead Total Ten-Minute Reserve Demand Quantity; Day-Ahead Total Thirty-Minute Operating Reserve Demand Quantity; Day-Ahead Total Ninety-Minute Reserve Demand Quantity; and Day-Ahead Total Four-Hour Reserve Demand Quantity). In this example, the participant would receive compensation (*i.e.*, the shadow price) for each constraint to which its resource contributes.

The energy options settlement construct involves both a day-ahead and a real-time settlement, similar to forward sales of energy today.[218] The day-ahead settlement will consist of a payment to the Market Participant at the day-ahead option clearing price for each megawatt of option sold. The real-time settlement will be based on what the participant delivers in real-time, if anything, and has two parts. The first part is the closeout charge (or closeout cost) for each MWh of the option sold, equal to the real-time price for energy minus the pre-determined option strike price, if that difference is positive. The second part of the real-time settlement is a credit, at the real-time price for energy, for the MWh that the resource actually produces. Section 4.3.1 of the ESI White Paper provides various examples of these settlement mechanics and outcomes. Because the Day-Ahead Ancillary Services are system-wide products, procured to satisfy system-level reserve requirements, the ISO's proposal provides for cleared Option Offers to be settled at a system-wide real-time energy price; *i.e.*, the hourly Real-Time Hub Price for energy.

The ISO will follow standard compensation principles, as the ESI White Paper explains.[219] Specifically, cleared offers to help satisfy a constraint will receive the clearing price corresponding to that constraint, such that physical energy supply offers that satisfy both the energy and the forecast energy constraint will be paid both the day-ahead price for energy (*i.e.*, the Locational Marginal Price) and the FERP,[220] and Option Offers cleared for EIR will be paid the FERP.[221] Similarly, physical resources that contribute to satisfying the GCR or RER demand quantities will be paid the corresponding clearing prices for each of the respective reserve products.[222] For example, an Option Offer cleared to provide GCR Day-Ahead Ten-Minute Spinning Reserve will be compensated the clearing price corresponding to that capability.

In exchange for the day-ahead payment, the hourly day-ahead option awards will be charged (closed out) at the real-time price for energy less the Option Strike Price, if positive.[223] This replacement cost-based settlement is discussed in Section 4.3.1 of the ESI White Paper, and, as illustrated therein, can have significant implications for the seller if the real-time energy price is high and the seller fails to

[218] *See* ESI White Paper, Section 4.3.1.

[219] *See id*.

[220] Section 6.2 of the ESI White Paper provides the rationale for paying the FERP to all physical resources that clear in the Day-Ahead Energy Market, and why that payment, in addition to the ay-ahead Locational Marginal Price does not constitute a double payment for resources supplying energy.

[221] *See* ESI White paper, Section 6.2. For completeness, day-ahead cleared virtual supply (*i.e.*, Increment Offers or INC) will be paid only the day-ahead price for energy, and not the FERP, as they are not physical supply and thus, do not contribute to satisfying the forecast energy requirement. *See id*. Section 6.5.

[222] *See id*. Sections 7.2.3 and 7.4.

[223] The proposed option closeout charge provisions are the same for all Day-Ahead Ancillary Services, but, as discussed in the Tariff provisions below, there are separate provisions for (i) GCR and RER and (ii) EIR to facilitate cross-referencing in the cost-allocation provisions.

produce energy in real-time.[224] Under this construct, for example, when the ISO purchases a 1 MWh energy option in the Day-Ahead Energy Market, the system acquires a right to 1 MWh of real-time energy at an up-front price (*i.e.*, the option price), and an incremental price of, at most, the Option Strike Price in real-time. If the Market Participant seller fails to deliver energy in real-time, the settlement rules put the seller "on the hook" for the incremental cost – *i.e.*, in excess of the Option Strike Price – to replace its energy. Thus, regardless of which resource is ultimately dispatched, the ISO acquires the 1 MWh of energy at the cost of, at most, the Option Strike Price, and the Market Participant seller incurs all additional costs, in excess of the Option Strike Price, to replace its energy when it does not provide energy in real-time.

Importantly, as the ESI White Paper explains, this "no excuse" settlement obligation is the only obligation of a Market Participant that acquires a Day-Ahead Ancillary Service obligation.[225] The Energy Security Improvements seek to align sellers' private incentives to incur energy supply costs with the expected replacement cost of (electricity) energy in real-time.[226] If a seller is unable to perform (for any reason), the market will rely on the least-costly alternative resource available in real-time to replace the energy from the non-performing resource, and charge the non-performing resource's owner for the additional cost of that replacement energy. Additional obligations beyond this "no excuse" settlement obligation would result in inefficiently high offer prices, and reduced market participation by competing suppliers.[227] These would undermine the cost effectiveness of the proposed design and unnecessarily increase consumer costs.

For clarity, settlement for energy and reserve in real-time remains unchanged. As is the case today and as illustrated in Section 4.3 of the ESI White Paper, energy and operating reserves provided in real-time will continue to be credited the corresponding real-time clearing price.

5. Cost Allocation of Credits and Charges

The ISO proposes to allocate the costs corresponding to the new energy and ancillary services based on the Commission's long-standing beneficiary-pays and cost-causation principles.

Specifically, based on the beneficiary-pays principle, the ISO proposes to allocate the costs for the credits paid to Market Participants for GCR and RER to Real-Time Load Obligation,[228] excluding

[224] *But see*, ESI White Paper, Section 4.3 (illustrating, through case (g), an instance where the resource's marginal costs are high, and therefore in real-time its production is uneconomic).

[225] *See id*. at Section 4.4.

[226] *See id*. at Section 5.1.

[227] *See id*. at Section 4.4.

[228] Real-Time Load Obligation is real-time load within the New England Control Area. *See* Tariff at § III.3.2.1(b)(i) (defining Real-Time Load Obligation for energy as "the MWhs of load, where such MWhs of load shall include External Transaction sales and shall have a negative value, at that location, adjusted for unmetered load and any applicable internal bilateral transactions which transfer Real-Time load obligations").

Real-Time Load Obligations associated with Storage Dispatchable Asset Related Demand Resources ("DARD").[229] Allocating these costs to Real-Time Load Obligation is appropriate because real-time load is the primary beneficiary of these services. Correspondingly, the associated credits for the closeout charges paid by GCR and RER sellers will be allocated to Real-Time Load Obligation (excluding Storage DARD) based on their *pro rata* share of all of Market Participants' Real-Time Load Obligations (excluding Storage DARD).[230]

As discussed in Section 6.6 of the ESI White Paper, the ISO proposes to allocate the costs for the credits paid to Market Participants for EIR to Market Participants with real-time negative load deviations and accepted virtual supply offers (*i.e.*, Increment Offers), with the balance of any remaining credits or charges allocated to Market Participants based on their pro rata share of all of Market Participants' Real-Time Load Obligations (excluding Storage DARD). For purposes of this cost allocation, the ISO will calculate a real-time load deviation amount for each Market Participant, equal to the greater of the difference between the Market Participant's Real-Time Load Obligation (excluding Storage DARD) and its Day-Ahead Load Obligation (excluding Storage DARD), or zero.[231] The ESI White Paper explains that allocating these costs to negative load deviations and accepted Increment Offers is appropriate, as they are the primary cost-driver of EIR to address load imbalances.[232] The associated credits for the closeout charges paid by sellers of EIR will be allocated similarly to load deviation and accepted Increment Offers. The deviations-based cost allocations address three mutually-exclusive scenarios or conditions: (1) the under-collection case, where the sum of Market Participants' load deviations and accepted Increment Offers is equal to or less than the EIR obligations; (2) an over-collection case, where the sum of all Market Participants' load deviations and accepted Increment Offers is greater than the EIR obligations, and the sum of all Market Participant's load deviations is greater than zero; and (3) an over-collection case, where the sum of all Market Participants' accepted Increment Offers is greater than the EIR amount, and the sum of all Market Participants' load deviations is zero.[233]

Finally, for the reasons provided in Section 6.6 of the ESI White Paper, the ISO proposes to allocate the FERP charges to day-ahead External Transaction sales[234] based on the beneficiary-pays cost-causation principles, and the remaining balance will be allocated, *pro rata*, to Real-Time Load Obligation (excluding real-time External Transaction sales and Storage DARD)[235] based on the

[229] *See* ESI White Paper, Section 7.4.

[230] *See id*.

[231] *See id*. at Section 6.6.

[232] *See id*.

[233] *See id*.

[234] Because cleared day-ahead External Transaction sales are explicit quantities and can be ascribed to specific Market Participants, each MWh of cleared day-ahead External Transaction sales will be charged the FERP.

[235] *See* ESI White Paper, Section 6.6.

beneficiary-pays principle. Allocating the FERP charges to day-ahead External Transaction sales, as the ESI White Paper explains, is appropriate because the ISO's next-day reliable Operating Plans include supporting the export of energy from the New England Control Area in real-time.[236] Day-ahead External Transaction sales benefit from and contribute to the costs associated with satisfying the forecast energy requirement. Because the proposal allocates the FERP charges to day-ahead External Transaction sales, there is no need to allocate the same costs to the associated real-time External Transaction sales. That would be tantamount to a double charge.

VI. TARIFF REVISIONS INCORPORATING THE ENERGY SECURITY IMPROVEMENTS AND COMPORTING CHANGES

Below, the ISO describes the structure and substance of the proposed changes to incorporate the Energy Security Improvements into its Tariff. The ISO also introduces corresponding changes to the Tariff: rules to sunset the Fuel Security Retention Mechanism and the Inventoried Energy Program for the fifteenth Forward Capacity Auction; and rules to facilitate the Internal Market Monitor's preparation of ad hoc reports concerning the competitiveness and performance of any major market design change, which would include the Energy Security Improvements.

A. Energy Security Improvements Tariff Provisions

The Tariff revisions implementing the Energy Security Improvements are contained in Section III of the Tariff, with newly defined terms used in those provisions reflected in Section I.2.2 of the Tariff. In incorporating these revisions, the ISO sought to minimize disruption to the existing framework and rules contained in Section III, some of which date back to the initial implementation of the Standard Market Design. The major provisions reflecting the key elements of the proposal are as follows:[237]

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[236] *See id*.

[237] The Tariff provisions filed here also reflect certain conforming changes corresponding to the addition of the Energy Security Improvements design. Substantive conforming changes are discussed in Sections V.B.1 and V.B.2 of this filing letter, and less substantive conforming changes are identified and addressed in the context of the corresponding design elements warranting the change. For completeness, the following conforming changes have been reflected in Sections I.2.2 and III of the Tariff:

- Revisions to the definition for the following defined terms to reflect the addition of the new energy and ancillary services in the Day-Ahead Energy Market, and their corresponding clearing prices and awards: Day-Ahead Adjusted Load Obligation, Day-Ahead Demand Reduction Obligation, Day-Ahead Energy Market, Day-Ahead Generation Obligation, Day-Ahead Load Obligation, Day-Ahead Locational Adjusted Net Interchange, Day-Ahead Prices, and Reserve Constraint Penalty Factors.

- Revisions to the following sections to also reflect the addition of the new energy and ancillary services in the Day-Ahead Energy Market: III.1.7.6, III.1.7.8A, III.1.10.1, III.1.10.1A, III.1.10.2, III.1.10.8(a)-(d), III.2.1, III.2.2, III.2.6(a), III.3.2.1(a), III.3.2.1(d)-(f), and III.4.1.

- Section III.1 (Market Operations) specifies the Option Offer requirements, the basis and timing for the Option Strike Price, and the Day-Ahead Ancillary Services' demand quantities, and describes the clearing and scheduling rules.

- Section III.2 (Day-Ahead Prices, Real-Time Prices, Locational Marginal Prices and Real-Time Reserves) specifies the clearing prices, including RCPFs, for the Day-Ahead Ancillary Services and the forecast energy requirement.

- Section III.3 (Accounting and Billing) describes the Day-Ahead Ancillary Services' obligations (*i.e.*, awards or schedules), and the payments and charges associated with those obligations.

The relevant provisions within each of these Tariff sections are discussed in turn below.

1. Section III.1.8 – Option Offers and Day-Ahead Ancillary Services Demand Quantities

New Section III.1.8 contains the main provisions applicable to Day-Ahead Ancillary Services' Option Offers and the corresponding demand quantities to be procured in the Day-Ahead Energy Market.

Section III.1.8.1 stipulates that the provisions contained in Section III.1.8 apply commencing on June 1, 2024, although the ISO has requested an effective date of November 1, 2020. This gap is appropriate to allow for implementation under settled rules and to facilitate the further build out of the rules to reflect implementation details. This timeframe is discussed in more detail in Sections VII and VIII.

Section III.1.8.2 provides that Market Participants may submit hourly offers to provide Day-Ahead Ancillary Services, consistent with the voluntary nature of the design, but if they choose to submit an offer, the offers must meet the specifications and requirements set forth in subsections (a) through (d).[238] Specifically, subsection (a) provides hourly Option Offers must be accompanied by a specific Generator Asset or Demand Response Resource for which the Market Participant also has submitted a corresponding Supply Offer or Demand Reduction Offer in the Day-Ahead Energy Market for the same hour of the Operating Day. This requirement enables the ISO to get to the underlying product – the energy – in real-time. Subsection (b) stipulates that the Option Offers must specify the hour of the Operating Day for which the Option Offer applies, an offer price (in $/MWh) that is greater than or equal to zero but does not exceed the Forecast Energy Requirement Demand Quantity RCPF, and an offer quantity (in MWh) that is greater than or equal to zero but does not exceed the associated physical resource's Economic Maximum Limit or Maximum Reduction, as specified in the corresponding Supply Offer or Demand Reduction Offer. As the Option Offers are resource specific, subsection (c) effects the limitation of only one Option Offer per Generator Asset or Demand Response

[238] *See* ESI White Paper, Section 4.6. A new Section III.1.10.1A(l) has been added to recognize the addition of Energy Call Option Offers, as a new offer type being considered in the Day-Ahead Energy Market scheduling process.

Resource for each hour in the Operating Day. Finally, subsection (d) sets forth the administrative timing and submission requirements for Option Offers. As set forth therein, Option Offers must be submitted by the offer submission deadline for the Day-Ahead Energy Market, which is specified in Section III.1.10.1A. Option Offers must be submitted each day; they are not standing offers.

Section III.1.8.3 specifies the basis and timing for publication of the Option Strike Price. This provision requires the ISO to specify an hourly Option Strike Price (in $/MWh) that represents a forecast of the expected Real-Time Hub Price for each hour of the Operating Day. Each hour of the Operating Day will have a unique Option Strike Price. In furtherance of transparency, Section III.1.3 also requires the ISO to use a forecast based on a publicly-available forecasting algorithm, and to identify that algorithm and review any potential changes to the forecasting process, prospectively, through the stakeholder process. This provision also requires the ISO to post, publicly, the value of the hourly Option Strike Price by no later than two hours before the Option Offer submission deadline for the Day-Ahead Energy Market. Recognizing the possibility for software failures or unforeseen circumstances, Section III.1.8.3 permits the publication of the hourly Option Strike Price at a different time.[239]

Section III.1.8.5[240] specifies the formulaic demand quantities (or requirements) for each Day-Ahead Ancillary Service to be procured through the Day-Ahead Energy Market for each hour of the Operating Day:

- *GCR*. Subsections (a) through (c) specify the required amounts for GCR, which correspond to the real-time analog. Specifically, the Day-Ahead Ten-Minute Spinning Reserve Demand Quantity equals the projected Ten-Minute Spinning Reserve Requirement; the Day-Ahead Total Ten-Minute Reserve Demand Quantity equals the projected Ten-Minute Reserve Requirement; and the Day-Ahead Total Thirty-Minute Operating Reserve Demand Quantity equals the projected Minimum Total Reserve Requirement. The specific real-time operating reserve requirements are as described in existing Section III.2.7A of Market Rule 1 and Operating Procedure No. 8.[241]

- *RER*. Subsections (d) and (e) specify the required amounts for RER. The Day-Ahead Total Ninety-Minute Reserve Demand Quantity amount equals the sum of (i) the reserve capability sufficient to satisfy the requirements in NERC Reliability Standard BAL-002-3 – Disturbance Control Standard – Contingency Reserve for Recovery from a Balancing Contingency Event, including the restoration of Contingency Reserve within the Contingency Reserve Restoration Period, and (ii) an allowance for load forecast error.[242] NERC BAL-002-3 establishes the requirement for Contingency Reserve to be restored

[239] *See, e.g.*, ISO Tariff at §§ III.1.10.8(b) and III.1.10.9(a) (accounting, similarly, for software errors or other events).

[240] Section III.1.8.4 of the Tariff is being reserved for future implementation details, to the extent any are identified during the implementation phase of the design.

[241] *See* ESI White Paper, Section 7.4

[242] *See id*.

within the Contingency Reserve Recovery Period, which is ninety minutes. The Day-Ahead Total Four-Hour Reserve Demand Quantity equals the sum of (i) the reserve capability sufficient to satisfy the requirements of NPCC Regional Reliability Reference Directory No. 5 Reserve, including the restoration of Thirty-Minute Operating Reserve within four hours of a deficiency, and (ii) an allowance for load forecast error.[243] NPCC Directory 5 establishes the requirement for Thirty-Minute Operating Reserve to be restored within four hours of a deficiency in those reserves. As defined by NERC and incorporated in Operating Procedure No. 8, the ISO currently uses Operating Reserves to address load forecast errors. Subsections (d) and (3) bring that existing functionality into the Tariff and provide for energy gaps that result from such errors to be addressed using RER capabilities, which are less expensive than the shorter response operating reserve capability currently used for that purpose. The detailed calculation for the application of the load forecast error relative to each RER quantity will be developed during the implementation phase for review by stakeholders and incorporation in the appropriate ISO Operating Procedures.

- *EIR*. Subsection (f) specifies the required amount of EIR. The Day-Ahead Energy Imbalance Reserve Demand Quantity to be procured is the difference between (a) the Forecast Energy Requirement Demand Quantity (*i.e.*, the estimated real-time load), and (b) the supply of physical energy cleared in the Day-Ahead Energy Market (*i.e.*, all Supply Offers and the total MWh of all Demand Reduction Offers that contribute to the forecast energy requirement constraint and therefore receive the FERP), and the net total External Transactions scheduled in the Day-Ahead Energy Market.[244]

Subsection III.1.8.6 specifies the Forecast Energy Requirement Demand Quantity.[245] That requirement is equal to the ISO's forecast for the total loads in the New England Control Area, which is calculated and posted publicly pursuant to existing Section III.1.10.1A(h).

2. Section III.1.10.8 – Clearing Process

Section III.1.10 sets forth the scheduling processes for implementing the Day-Ahead Energy Market and the Real-Time Energy Market. Current Section III.1.10.8(a) describes the clearing and scheduling considerations for both of these energy markets. To incorporate the Energy Security Improvements, the ISO has divided subsection (a) into two separate subsections: subsection (a)(i), which preserves the existing rules that will continue to apply until June 1, 2024; and new subsection (a)(ii), which incorporates the rules applicable commencing on June 1, 2024.[246]

[243] *See id*.

[244] *See id*. at Section 6.4.

[245] *See id*.

[246] Ministerial changes have been incorporated in Section III.1.10.8(a)(i) to improve readability.

New Section III.1.10.8(a)(ii) contains the primary Day-Ahead Energy Market co-optimization provisions.[247] This section, based on the structure of the existing scheduling considerations provisions (now subsection (a)(i)),[248] extends the existing energy-only Day-Ahead Energy Market to a Day-Ahead Energy Market that clears both energy and ancillary services, and incorporates the forecast energy requirement.[249] The first paragraph in Section III.1.10.8(a)(ii) provides for the Day-Ahead Energy Market clearing to jointly optimize: (1) Demand Bids, Decrement Bids, Demand Reduction Offers, Supply Offers, Increment Offers, and External Transactions, for energy; (2) Option Offers to satisfy each Day-Ahead Ancillary Service demand quantity; and (3) Supply Offers, Demand Reduction Offers, External Transactions, and Option Offers to satisfy the Forecast Energy Requirement Demand Quantity. The second paragraph mirrors the existing second paragraph of Section III.1.10.8(a). It continues to enumerate the factors considered in clearing the Day-Ahead Energy Market, with two substantive changes: item (5) has been generalized to account for the ancillary services more broadly, in order to accommodate the new ancillary services proposed in this filing, and item (6) expressly notes that clearing will account for resources' physical operating characteristics, for Option Offer clearing depends on those capabilities.

Finally, the third paragraph in Section III.1.10.8(a)(ii) incorporates the technical eligibility requirements for clearing Option Offers to satisfy the GCR, RER and EIR demand quantities. Section III.1.10.8(a)(ii)(1) provides for the ISO to take into account only Option Offers associated with Generator Assets or Demand Response Resources that meet the real-time operating reserve eligibility requirements for purposes of satisfying the GCR and RER demand quantities. It also provides for the ISO to take into account only Option Offers associated with a Day-Ahead committed physical resource or a fast-start resource for purposes of satisfying the EIR demand quantity.

[247] The ISO also proposes to revise §III.1.7.6(a), §III.1.10.2(b), §III.2.1, and §III.2.2 to recognize the Day-Ahead Energy Market will be co-optimized, and for consistency with the new co-optimized clearing provisions in §III.1.10.8.

[248] The existing Section III.1.10.8(a) captures the scheduling considerations for the Day-Ahead Energy Market, as well as what occurs after the Day-Ahead Energy Market clearing. Incorporating the language reflected in the existing Section III.1.10.8(a)(ii), which relates to the scheduling process after the Day-Ahead Energy Market clearing, at the end of the new provisions would introduce confusion and disrupt the flow of the new provisions, which apply only to the Day-Ahead Energy Market clearing process. To avoid confusion, the ISO proposes to move the concept captured in the existing Section III.1.10.8(a)(ii) language to Section III.1.10.8(c). The existing Section III.1.10.8(a)(ii) more appropriately fits into that provision because it relates to the process after the Day-Ahead Energy Market clears. As revised, the provision provides for the "ISO to use its best efforts to determine the least-cost means to satisfy any remaining reliability requirements of the New England Control Area for the Operating Day."

[249] Currently, Section III of the Tariff reflects the old term "least-cost" in describing the objective function of the Day-Ahead Energy Market. That terminology creates ambiguity with the addition of price demand bids in the market. A more appropriate terminology is "economic commitment and dispatch," which implies both a least-cost solution and that the demand quantity is the economically correct demand quantity. Since the term "economic" implies the solution is "least-cost" as well, when adding new provisions/language the ISO used "economic" before"commitment and dispatch" instead of "least-cost." This change is reflected in Section III.1.7.6(a), III.1.10.8(a)(ii), and III.2.2. The ISO did not delete "least-cost" from all existing provisions where the term is used, consistent with its overall objective to minimize the changes to existing provisions as part of this compliance effort.

3. Section III.2.6 – Clearing Prices and RCPFs

Section III.2.6 (Calculation of Nodal Day-Ahead Prices) has been divided into two separate sections: Section III.2.6.1 (Calculation of Day-Ahead Locational Marginal Prices), and Section III.2.6.2 (Calculation of Additional Day-Ahead Prices).[250] Section III.2.6.1 reflects the existing provisions for determining the day-ahead price for energy, with minor revisions to recognize the Option Offers clearing along with energy in the co-optimized Day-Ahead Energy Market, and to account for the effect on ancillary services costs associated with increasing the output of a resource or reducing consumption of a resource.[251] These revisions account for the opportunity costs of marginal units not providing ancillary services.

New Section III.2.6.2(a) describes the clearing prices for the Day-Ahead Ancillary Services and the forecast energy requirement demand quantity constraints. Subsections (i) through (v) describe the clearing prices for GCR and RER, with each provision reflecting the price cascading logic.[252] For example, the clearing price for Day-Ahead Ninety-Minute Reserve reflects the incremental cost to satisfy the next increment of the Day-Ahead Total Ninety-Minute Reserve Demand Quantity and the clearing price for the Day-Ahead Four-Hour Reserve, which is the lower value reserve. Subsection (vi) describes the clearing price for EIR, which is the FERP, and subsection (vii) describes the FERP, which is the clearing price for the forecast energy requirement constraint.[253]

New Section III.2.6.2(b) specifies the RCPFs (*i.e.*, the maximum redispatch cost to meet a demand quantity) applicable to each Day-Ahead Ancillary Service demand quantity and the Forecast Energy Requirement Demand Quantity. Subsections (i) through (iii) specify the RCPFs applicable to the GCR demand quantities, which are based on the RCPFs applicable to the corresponding real-time requirements.[254] The Day-Ahead Ten-Minute Spinning Reserve RCPF has the same value as the Real-Time Ten-Minute Spinning Reserve Requirement RCPF ($50/MWh); the Day-Ahead Total Ten-Minute Reserve Demand Quantity has the same value as the Real-Time Ten-Minute Reserve Requirement RCPF ($1,500/MWh); and the Day-Ahead Total Thirty-Minute Operating Reserve

[250] The ISO also proposes to add new Section III.1.7.8A to recognize the additional Day-Ahead Ancillary Services clearing prices.

[251] The ISO proposes to incorporate conforming changes in the existing Locational Marginal Price provisions (Section III.2.6.1) to enable the day-head price to properly account for the impact of the (marginal) cost of energy imbalance reserve, as illustrated in the Example 3-B in Section 6.3 of the ESI White Paper. *See* ESI White Paper, Sections 6.3-6.4.

[252] *See id*. at Sections 7.2.3 and Section 7.4.

[253] *See id*. at Section 6.4.

[254] *See id*.

Demand Quantity RCPF has the same value as the Real-Time Minimum Total Reserve Requirement RCPF ($1,000/MWh).[255]

Subsections (iv) and (v) specify the RCPFs for the RER demand quantities.[256] The RCPF for Day-Ahead Total Ninety-Minute Reserve Demand Quantity is set at $250/MWh, and the RCPF for Day-Ahead Total Four-Hour Reserve Demand Quantity is set at $100/MWh. Lastly, the RCPF for the Forecast Energy Requirement Demand Quantity is specified in subsection (vi), and is set at 101% of the sum of all of the RCPFs in subsections (i) through (v), which equals $2,992/MWh. [257] There is no separate RCPF for EIR because that requirement is based on the Forecast Energy Requirement Demand Quantity.

4. Section III.3.2.1 – Day-Ahead Ancillary Services Obligations; Allocation of Credits and Charges

Section III.3.2.1(a) (currently, Day-Ahead Energy Market Obligations) has been split into two subsections, with subsection (a)(1) reflecting the existing obligations of Market Participants with energy offers that clear in the Day-Ahead Energy Market, and new subsection (a)(2) incorporating the obligations of Market Participants that clear Option Offers that contribute toward satisfying a specific Day-Ahead Ancillary Service demand quantity. New Sections III.3.2.1(a)(2)(i) through (iii) specify Day-Ahead Ancillary Services obligations corresponding to Option Offers that clear to satisfy the GCR demand quantities;[258] subsections (iv) and (v) specify the Day-Ahead Ancillary Services obligations corresponding to Option Offers that clear to satisfy the RER demand quantities;[259] and subsection (vi) specifies the Day-Ahead Ancillary Services obligations corresponding to Option Offers that clear to satisfy the EIR demand quantity.[260] Market Participants' Day-Ahead Ancillary Services obligations are specific to the corresponding demand quantity to which the Market Participant's resource contributes. As noted, the clearing prices corresponding to the GCR and RER demand quantities incorporate the clearing prices of reserves lower down the hierarchy. Correspondingly, Section III.3.2.1(a)(2) excludes the Option Offer amounts cleared toward satisfying the higher requirement in each subsection to avoid double counting.[261]

New Section III.3.2.1(q)(1) reflects the sellers' day-ahead payment credit corresponding to the new Day-Ahead Ancillary Services. This provision stipulates that each MWh of Day-Ahead Ancillary

[255] *See id*. The RCPFs for the real-time analog are specified in Section III.2.7A.

[256] *See* ESI White Paper, Section 7.4.

[257] *See id*. at Section 6.4.

[258] *See id*. at Section 7.4.

[259] *See id*.

[260] *See id*. at Section 6.4.

[261] *See* ESI White Paper, Section 7.4.

Service obligation will be paid the clearing price corresponding to the obligation. Sections III.3.2.1(q)(1)(i)-(iii) provide for Market Participants with Day-Ahead Ancillary Service obligations for GCR products to receive a credit for the corresponding GCR clearing price. Subsections (iv) and (v) provide for Market Participants with Day-Ahead Ancillary Services obligations for RER products to receive a credit for the corresponding RER clearing price. Subsection (vi) provides for Market Participants with a Day-Ahead Ancillary Services obligation for EIR to receive the corresponding EIR clearing price (*i.e.*, the FERP).[262]

New Section III.3.2.1(q)(2) reflects the sellers' real-time settlement closeout charge corresponding to the new Day-Ahead Ancillary Services. It provides for each MWh of Day-Ahead Ancillary Service obligation to be charged the energy option closeout amount. Specifically, Sections III.3.2.1(q)(2)(i) (for GCR and RER) and (ii) (for EIR) provide that each Market Participant with a Day-Ahead Ancillary Service obligation will be charged the greater of the closeout charge rate and zero.[263] The closeout charge rate shall be the hourly Real-Time Hub Price less the Option Strike Price for the hour.[264]

New Section III.3.2.1(q)(3) sets forth the cost allocation provisions corresponding to GCR and RER. Section III.3.2.1(q)(3)(a)(i) provides for the sum of all credits paid to Market Participants supplying GCR and RER pursuant to Sections III.3.2.1(q)(1)(i)-(v) to be charged to Market Participants based on their pro rata share of the sum of all Market Participants' Real-Time Load Obligations (excluding Real-Time Load Obligations associated with Storage DARD).[265] Section III.3.2.1(q)(3)(a)(ii) provides for the sum of all closeout charges calculated pursuant to Section III.3.2.1(q)(2)(i) to be credited to Market Participants based on their pro rata share of the sum of all Market Participants' Real-Time Load Obligations (excluding Real-Time Load Obligations associated with Storage DARD). [266]

New Section III.3.2.1(q)(4) sets forth the cost allocation provisions corresponding to EIR.[267] Section III.3.2.1(q)(4)(ii) describes the cost allocation for the EIR credits owed to Market Participants supplying EIR pursuant to Section III.3.2.1(q)(1)(vi), and Section III.3.2.1(q)(4)(iii) describes the allocation of the credits received from the closeout charges paid by Market Participants supplying EIR under Section III.3.2.1(q)(2)(ii).[268] Both Sections III.3.2.1(q)(4)(ii) and (iii) contain three paragraphs

[262] *See id*. at Section 6.6.

[263] *See id*.

[264] The closeout charge is the same for GCR, RER and EIR. The EIR is reflected in a separate provision to facilitate cross-reference in the corresponding cost allocation provisions.

[265] *See* ESI White Paper, Section 7.4.

[266] *See id*.

[267] *See id* at Section 6.6.

[268] *See id*.

describing three mutually exclusive conditions described in Section V.A.5 of this filing letter. Both sections follow the same parallel construct for the three conditions.[269]

Under the first condition, both credits paid and closeout charges are allocated to accepted Increment Offers and negative load deviations with remaining balances charged to Market Participants based on their pro rata share of the sum of all Market Participants' Real-Time Load Obligations (excluding Real-Time Load Obligations associated with Storage DARD). Under the second condition, both credits paid and closeout charges are allocated to accepted Increment Offers and negative load deviations, with any remaining balances credited to Market Participants based on their pro rata share of the sum of all Market Participants' Real-Time Load Obligations (excluding Real-Time Load Obligations associated with Storage DARD). Under the third condition, both credits paid and closeout charges are allocated to accepted Increment Offers.

For purposes of Section III.3.2.1(q)(4), Section III.3.2.1(q)(4)(i) requires the ISO to calculate a load deviation amount for each Market Participant, equal to the greater of the difference between the Market Participant's Real-Time Load Obligation and its Day-Ahead Load Obligation, or zero.[270]

New Sections III.3.2.1(q)(5) and III.3.2.1(q)(6) set forth the credits and charges corresponding to the forecast energy requirement. Section III.3.2.1(q)(5) provides for the FERP to be paid to each Market Participant with Generator Assets, Demand Response Resources, and External Transactions for the supply of energy scheduled in the Day-Ahead Energy Market (*i.e.*, cleared physical supply of energy).[271] Section III.3.2.1(q)(6) provides for those credits to be charged to Market Participants with cleared day-ahead External Transaction sales, and the balance of any remaining credits to be charged to Market Participants based on their pro rata share of the sum of all Market Participants' Real-Time Load Obligations (excluding Real-Time Load Obligations associated with Real-Time External Transaction sales and Storage DARD).[272]

B. Corresponding Tariff Revisions With Proposed Energy Security Improvements' Implementation

1. Revisions to Sunset the Fuel Security Retention Mechanism and the Inventoried Energy Program for FCA 15, Upon Commission Acceptance of the Energy Security Improvements

As reflected in the proposed Tariff provisions, the provisions corresponding to the Energy Security Improvements take effect on June 1, 2024. To allow the design to operate most effectively, the ISO proposes to eliminate two interim out-of-market programs that were designed to bridge the gap

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[269] *See id*.

[270] *See* ESI White Paper, Section 6.6.

[271] *See id*.

[272] *See id*.

to the Energy Security Improvements. Assuming the Commission approves the Energy Security Improvements filed herewith, these two programs will be unnecessary, and could diminish the new design's impact.

Specifically, the ISO proposes to sunset the Fuel Security Retention Mechanism[273] and the Inventoried Energy Program for FCA 15. FCA 15 corresponds to the June 2024 through May 2025 Capacity Commitment Period. In each case, sunsetting is conditional upon the Commission's acceptance of the Energy Security Improvements Tariff provisions effective November 1, 2020 for implementation on June 1, 2024.

Regarding the Fuel Security Retention Mechanism, the ISO's proposal to sunset this interim mechanism is consistent with the December 3 Order accepting the interim mechanism. Therein, the Commission stated:

> This interim solution is solely a stop-gap measure to address the fuel security challenges facing the region while ISO-NE develops its long-term market-based approach. We agree with the dissent that the value of these resources must be accurately reflected in the market in order to address fuel security issues in the long term . . . In addition, we anticipate that the long-term market solution will obviate the need to continue to use the interim solution approved in this order. Accordingly, ISO-NE's filing must contain language that will remove from its tariff the short-term solution, if accepted.[274]

This requirement is also reflected in the Commission's February 14 Order, wherein the Commission rejected the ISO's proposal to sunset the Fuel Security Retention Mechanism prior to the commencement of the FCA 15 qualification process. In that order, the Commission reiterated the requirement that ISO seek to "remove the Fuel Security Reliability Mechanism from its Tariff if the Permanent Market Solution is accepted."[275]

The Tariff revisions necessary to effectuate the early termination of the Fuel Security Retention Mechanism are reflected in Section III.13.2.5.2.5A and Appendix L to Market Rule 1. The revisions in Section III.13.2.5.2.5A clarify that the operative fuel security reliability review provisions will only be in effect for two Forward Capacity Auction cycles – the 2022-2023 Capacity Commitment Period corresponding to the thirteenth Forward Capacity Auction, and the 2023-2024 Capacity Commitment Period corresponding to the fourteenth Forward Capacity Auction ("FCA 14"). The revisions also remove references to the applicability of the rules for FCA 15. The revisions to Appendix L, which contains the fuel security reliability retention triggers, remove language providing for the application of the rules for FCA 15.

[273] *See* Tariff at §§ III.13.2.5.2.5A and III.L (reflecting the operating fuel security reliability review provisions, and the retention triggers).

[274] December 3 Order at PP 96-97.

[275] February 14 Order at P 19.

The ISO also proposes to sunset the Inventoried Energy Program for the second winter it is to be in place (*i.e.*, the winter months of 2024-2025), again subject to the Commission's acceptance of the Energy Security Improvements Tariff provisions effective November 1, 2020 for implementation on June 1, 2024. The ISO proposed to implement the Inventoried Energy Program for the winter months of 2023-2024 and 2024-2025 to provide incremental compensation to resources that maintain inventoried energy during cold periods. The ISO's filing of this program stemmed from a commitment to identify an interim solution that could serve alongside the Fuel Security Retention Mechanism while the efforts to develop a long-term, market-based solution were ongoing. The Commission's acceptance of the Energy Security Improvements for implementation in June 2024 would obviate the need for the Inventoried Energy Program for the second winter. The early termination of the program upon the Commission's acceptance of the Energy Security Improvements for June 2024 would limit the application of the program to the winter months of 2023-2024, and avoid any overlap with the long-term market solution.

To effectuate the early termination of the Inventoried Energy Program, the ISO proposes to revise Section I.2.2 of the Tariff and Attachment K to Market Rule 1, which contains the provisions implementing the program. The revisions reflected in those provisions limit the ISO's administration of the program to only the winter of 2023-2024.

Terminating these interim measures a year or winter earlier, coincident with the proposed implementation of the Energy Security Improvements, is necessary to avoid undermining the efficacy of the long-term market or in any way hindering the transition to that solution. Recent efforts to alleviate the region's fuel security concerns have focused on short-term measures, including out-of-market mechanisms that pay selected generation resources to procure additional fuel. These mechanisms ultimately interfere with the ISO's ability to address the region's energy security in a sustainable manner. The proposed Energy Security Improvements provide a market-based mechanism to address the region's energy security concerns by procuring, through the market, energy and reserve products that are closely aligned with established reliability criteria. By earning greater market-based compensation for these products, Market Participants will have greater financial incentives to firm-up incremental energy supplies in advance, so their resources can perform during cold weather conditions—and whenever they are needed during the course of the year. For the Energy Security Improvements to achieve these ends, however, it is critical that the markets not be impeded by interference from these interim measures.[276] The market design can only function if it can competitively price the reliability need without interference from out-of-market measures that provide the same services under a non-market price.

[276] An uneconomic retention, for example, will tend to increase the available energy supply relative to a scenario with no such retention (*i.e.*, where the resource exits the market), and is therefore likely to reduce the wholesale energy and reserve prices paid to all resources. These lower prices will tend to reduce the incentive for Market Participants to provide energy and reserves relative to the scenario where no uneconomic retention occurs. Among the price signals that would be affected are those associated with the Energy Security Improvements.

2. Revisions Providing for IMM's Performance and Competitiveness Review of Major Market Enhancements, such as the Energy Security Improvements

In response to stakeholder concerns raised during the stakeholder process regarding the competitiveness and performance of the Energy Security Improvements,[277] the ISO proposes to revise Appendix A of Market Rule 1 to add a new ad hoc reporting requirement on the overall competitiveness and performance of the New England Markets, including major market design. This new requirement is reflected in new Section III.A.17.2.5.

Briefly, Appendix A of Market Rule 1 contains the market monitoring and mitigation functions to be performed by the Internal Market Monitor, as well as the External Market Monitor. Among the core functions of the Internal Market Monitor set forth therein is the "[r]eview the competitiveness of the New England Markets, the impact that market rules and/or changes to the market rules will have on the New England Markets and the impact that ISO's actions have had on the New England Markets."[278] The Internal Market Monitor must also "[p]repare an annual state of the market report on market trends and the performance of the New England Markets, as well as less extensive quarterly reports,"[279] "[p]erform such additional monitoring as the Internal Market Monitor deems necessary . . . [and] include significant results of such monitoring in its reports under Section III.A.17 of this Appendix A."[280] Currently, Section III.A.17.2.2 sets forth quarterly, and Section III.A.17.2.4 sets forth annual reporting requirements.

As reflected in the Tariff provisions filed here, the ISO proposes to add a new Section III.A.17.2.5, which provides the Internal Market Monitor the sole discretion to issue ad hoc reports concerning the competitiveness and performance of any major market design change, which would include the Energy Security Improvements. The proposed revisions provide for the Internal Market Monitor to issue ad hoc reports on the competitiveness of any major market design change within one year of the effective date of operation, subject to adequate available data. Ad hoc reports on the major market design change's performance would be issued within three years of the effective date of operation, subject to adequate available data.

While reserving the ability to solicit and/or receive input from the External Market Monitor, Market Participants and other stakeholders, including New England state public utility commissions,

[277] For example, the New England States Committee on Electricity and the Massachusetts Office of the Attorney General proposed a joint amendment that would have required that the Internal Market Monitor issue a quarterly "certification" of competitiveness, without specifying any test criteria or standards on which to base such a certification, and a separate "look back" joint amendment that would have required "input" from stakeholders, state public utility commissions and Market Participants to "determine the methods, approaches, information and criteria the Internal Market Monitor will use to conduct the analysis of the performance and effectiveness of the Day-Ahead Ancillary Services."

[278] Tariff at § III.A.2.3(e).

[279] *Id.* at § III.A.2.3 (g).

[280] *Id.* at § III.A.2.3 (k).

proposed Section III.A.17.2.5 provides that the Internal Market Monitor shall have sole discretion as to the methodology and criteria used to conduct its independent analysis. The Internal Market Monitor shall describe its methodology and criteria, its significant findings and, if any, recommendations. The Section further provides for the Internal Market Monitor to file the finalized ad hoc reports with the Commission and post them on the ISO's website. Thereafter, the proposed rule provides for the Internal Market Monitor to continue reporting on the competitiveness and performance of major market design changes in its quarterly and/or annual reports.

VII. IMPLEMENTATION WORK AND SCHEDULE

As reflected in the Tariff rules filed here, the proposed implementation date for the Energy Security Improvements is June 1, 2024, which is the start of the 2024-2025 Capacity Commitment Period associated with FCA 15. Designing and implementing this long-term, market solution is a large, complex, and multi-year project. The ISO has purposefully scheduled implementation of the Energy Security Improvements for June 2024, so that there is adequate time for the extensive implementation activities. This timeline also affords Market Participants certainty about the future market rules and time to make their preparations.

The Tariff rules filed here are the foundation for the long-term, market solution, including related market design enhancements and conforming changes that the ISO and stakeholders have not yet addressed. Prompt Commission action on the rules filed here is critical for these activities by the ISO and stakeholders to proceed and be completed by June 2024. For these reasons, in Section VIII of this filing letter, the ISO respectfully requests Commission action on the rules filed here by no later than November 1, 2020.

In support of its request, below, the ISO explains how the Commission's action on or before November 1st will help allay market uncertainties. Next, the ISO describes the implementation work ahead of the June 2024 implementation date.

A. Market Certainty Before Upcoming Forward Capacity Auctions

A Commission Order no later than November 1, 2020 will provide Market Participants with greater certainty as to the Tariff rules that will be in effect for the 2024-2025 Capacity Commitment Period and periods thereafter. As discussed, the proposed implementation date for the Energy Security Improvements' Day-Ahead Ancillary Services is June 1, 2024, which coincides with the start of the FCA 15 2024-2025 commitment period. Given the proposed implementation date, the first Forward Capacity Auction that will be affected is FCA 15, which is scheduled for February 8, 2021. The qualification process for that auction and activities related to subsequent commitment periods are already underway and scheduled to commence, respectively. A Commission Order no later than

November 1st will help inform Market Participants' forward-looking expectations of market conditions, as explained below.

Certainty for FCA 15 Activities. Under the current Tariff rules, the Inventoried Energy Program is to be in place for the winters of 2023-2024 and 2024-2025, which occur during the Capacity Commitment Periods for FCA 14 and FCA 15. As discussed in Section VI.B.1, above, to avoid interference with the proper functioning of the Energy Security Improvements, the Tariff rules filed here also reflect revisions to sunset that interim measure after the 2023-2024 winter, conditional upon the Commission's acceptance of the Tariff rules incorporating the Energy Security Improvements included in this compliance filing. Because the early sunset of the Inventoried Energy Program is contingent upon the Commission's acceptance of the Energy Security Improvements, until the Commission issues an Order addressing this filing, the ISO and Market Participant will be managing two sets of de-list bids and new supply offers for FCA 15: one that reflects the impacts of the Inventoried Energy Program, in the absence of the Energy Security Improvements' Day-Ahead Ancillary Services, and one that reflects the impacts of the Energy Security Improvements' Day-Ahead Ancillary Services, in the absence of the Inventoried Energy Program. A Commission Order by November 1st will ensure that the appropriate bids/offers are accounted for in the ISO's informational filing for FCA 15, which is scheduled to be filed on November 10, 2020, and ultimately used in the auction.[281]

Certainty for FCA 16 Activities. The current Tariff rules require the ISO to review and recalculate a number of the parameters to be used for FCA 16, which corresponds to the 2025-2026 Capacity Commitment Period. The parameters that must be updated include: the Cost of New Entry ("CONE"), Net CONE, Offer Review Trigger Prices, the Dynamic De-List Bid Threshold, and the Capacity Performance Payment Rate (collectively, the "FCM Parameters"). Because the Tariff rules that will be in effect for the 2025-2026 period are contingent upon the Commission's acceptance of this compliance filing, until the Commission issues an Order, the ISO and Market Participants will be evaluating two sets of FCM Parameters' values: one that reflects the current market rules, in the absence of the Energy Security Improvements' Day-Ahead Ancillary Services, and one that reflects the impacts of the Energy Security Improvement' Day-Ahead Ancillary Services. Developing the FCM Parameters involves a multi-month analysis and stakeholder process that culminates in a filing of the values for the Commission's acceptance by March 2021, in order to have the recalculated values effective ahead of the FCA 16 qualification process. A Commission Order on the Energy Security Improvements by November 1st will ensure that the appropriate FCM Parameter values are reflected in the ISO's filing.

B. Additional Design and Implementation Work

1. Market Power Analysis and Mitigation

[281] *See* Tariff at § III.13.8(c). If the Commission accepts the Energy Security Improvements, as reflected in the Tariff rules filed here, effective November 1, 2020 for implementation on June 1, 2024, then the de-list bids and supply offers associated with the Energy Security Improvements' Day-Ahead Ancillary Services will be used in FCA 15. If a Commission Order is not issued before the ISO must finalize its inputs for conducting FCA 15 on February 8, 2021 **(*i.e.*, by January 21, 2021)**, then the ISO will use in the auction the de-list bids and supply offers that reflect the impact of the Inventoried Energy Program, absent the Energy Security Improvements' Day-Ahead Ancillary Services.

The Tariff provisions filed here reflect the market-based mechanism for addressing the region's energy security needs in a long-term and sustainable manner, and substantially comply with the Commission directives in the July 2 Order. The ISO recognizes that a market power assessment ("MPA") to support the Energy Security Improvements' Day-Ahead Ancillary Services is a necessary component of a market-design proposal.[282] Accordingly, the ISO has been working steadily on the mitigation-related work, but additional time is needed to complete the required MPA and develop an appropriate mitigation proposal.

Commission action on the rules filed here on or before November 1st would allow the ISO to account for the Commission's determination before it completes the MPA and the appropriate mitigation proposal. The ISO anticipates completing the MPA analysis and filing the results of that assessment, along with the appropriate mitigation proposal supported by those results, by the fourth quarter of 2021. A filing in that period would allow sufficient time for the ISO's completion of the mitigation-related work, briefly described below, and robust stakeholder consideration of that work. In turn, this timing should ensure that effective market power mitigation measures are in place for the implementation of the Energy Security Improvements' Day-Ahead Ancillary Services on June 1, 2024, as proposed.

The ongoing mitigation-related work in preparation for a filing by the date specified above consists, primarily, of three steps. These are: (1) conceptual mitigation design discussions; (2) the MPA analysis; and (3) detailed mitigation design and associated market rule development.[283] As detailed below, the first two steps are proceeding in parallel and are underway. The third step will proceed subsequently, given its dependence on the preceding steps.

The conceptual mitigation discussions commenced at the NEPOOL Markets Committee in January 2020, with the ISO's External Market Monitor sharing its perspective on mitigation for co-optimized Day-Ahead Energy Markets.[284] These continuing discussions were intended to facilitate understanding of how mitigation approaches can address potential market power, while enabling competition to set price when competitive conditions prevail. They also enabled the ISO and stakeholders to more fully understand practical implementation issues that may arise with particular mitigation approaches. In the discussion, the External Market Monitor shared its findings that the ISO's

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282 *See Midwest Indep. Transmission Sys. Operator, Inc.*, 116 FERC ¶ 61,311, at PP 42-43, *reh'g denied* 120 FERC ¶ 61,202 (2007).

283 *See* ISO-NE Memorandum to NEPOOL Markets Committee, *Energy Security Improvements: Market Power Assessment Analysis Update* (Jan. 22, 2020), https://www.iso-ne.com/static-assets/documents/2020/01/a3_c_iso_memo_esi_market_power_assessment_update.pdf ("January 22 MPA Analysis Memo"); ISO-NE Memorandum to NEPOOL Markets Committee, *Energy Security Improvements: Planned Scope of Mitigation-Related Work for Day-Ahead Ancillary Services* (Nov. 6, 2019), https://www.iso-ne.com/static-assets/documents/2019/11/a4_d_iso_memo_re_esi_mitigation_work.pdf.

284 *See* Potomac Economics Memorandum to ISO New England and NEPOOL Markets Committee, *Day-Ahead Market Power Mitigation* (Jan. 21, 2020), https://iso-ne.com/static-assets/documents/2020/01/a3_b_emm_memo_day_ahead_market_power_mitigation.pdf (offering recommendations and addressing stakeholder questions).

conduct and impact mitigation framework would likely be effective in addressing potential mitigation concerns related to the proposed, new Day-Ahead Ancillary Services, and noted the importance of the ongoing MPA work to determine how mitigation measures should be applied and to establish the appropriate thresholds.[285]

The ISO anticipates reviewing the MPA results and their implications with stakeholders in the fourth quarter of 2020.[286] The purpose of this analysis is to determine, quantitatively, whether and when market power is an empirically-supported concern. If the concern exists, the analysis will strive to identify the specific conditions, frequency, and extent to which individual Market Participants may be able to profitably exercise market power, and to provide useful input into the design and the mitigation rules and procedures.

Following the completion of the MPA analysis and the conceptual mitigation discussions, the ISO anticipates developing a mitigation design proposal and associated market rules for stakeholders' consideration. That proposal will be informed by the specific results of the MPA analysis, quantitative evaluation of potential mitigation design components using the MPA analysis model, and the External and Internal Market Monitors' guidance concerning offer mitigation for Day-Ahead Ancillary Services. Assuming that the Commission issues an order on the instant filing or before November 1st, the ISO anticipates initiating stakeholder discussions on a mitigation proposal in the first quarter of 2021 for filing in the fourth quarter of 2021. This would provide adequate time for robust stakeholder consideration, Commission review, and incorporation of this element into the overall implementation schedule for the Energy Security Improvements.

2. Development of a Seasonal Forward Market to Complement the Energy Security Improvements

The ISO has been exploring the potential of a seasonal forward market, and, at this time, it intends to pursue a forward element to complement the Energy Security Improvements' Day-Ahead Ancillary Services filed here. According to the ISO's initial analysis, a seasonal forward market could

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[285] *See id*. at 12-13.

[286] The MPA will include detailed simulations of the Day-Ahead Energy Market based on modeling the new Day-Ahead Ancillary Services and constraints as proposed for sample days when the exercise of market power might be profitable, absent measures to mitigate it. Underlying this analysis are the following four steps: (1) developing a study model of the co-optimized market clearing software, (2) developing study cases and input data, (3) modeling participants' Option Offers, and (4) evaluating the market clearing outcomes. *See* January 22 MPA Analysis Memo at 1-2. These steps entail a sequential work process, as each builds upon the prior, but some interaction between certain steps is expected. As of this filing, the ISO has completed the first step. Specifically, the ISO has developed and coded a study model of the Day-Ahead Energy Market clearing with the addition of the proposed Day-Ahead Ancillary Services requirements. The model simulates the co-optimization objective and constraints, and accounts for resources' physical and economic offer parameters, the unit commitment process, interface transmission constraints, individual units' ramping and reserve capabilities, and other inputs into the current and proposed day-ahead market clearing process. The model also incorporates the co-optimized Day-Ahead Energy Market's pricing logic, as discussed in this filing. The ISO has also made significant progress on the second step, and expects to complete that and the remaining steps by the fourth quarter of 2020.

further help the region procure the Day-Ahead Ancillary Services cost-effectively. Specifically, the ISO's initial work has identified a set of conditions where a forward auction may further improve market efficiency, using a potential two-settlement design where suppliers could sell these services via a forward auction held some months in advance of the delivery period.[287]

While the potential value and conceptual framework for a forward element appear to be sound, the ISO has not had sufficient time to evaluate and design a detailed proposal. Developing a forward market would be another major undertaking, and certainty regarding the foundational component for such a market, *i.e.*, the Day-Ahead Ancillary Services proposed in this filing, is necessary before the ISO can move forward. Assuming the Commission issues an Order on this compliance filing on or before November 1st, the ISO anticipates developing a seasonal forward market proposal and bringing it through the stakeholder process in 2021.

3. Additional Follow-on Work Related to the Energy Security Improvements' Day-Ahead Ancillary Services

Typically, an effort of the Energy Security Improvements' magnitude entails significant internal work prior to filing in order to resolve all design, technical, and implementation details and address all related conforming design and process changes. While the rules filed here reflect the complete design for the core Energy Security Improvements' Day-Ahead Ancillary Services, given the compliance schedule constraints, they do not address all matters that are relevant to the implementation of this design. Additional follow-on design work and filings will be necessary in order to fully integrate the new Day-Ahead Ancillary Services into related market rules, including conforming changes to Net Commitment Period Compensation rules, financial assurance requirements, and rules for establishing resource RER-related capabilities.

The ISO anticipates identifying other areas requiring conforming changes as well. Some initiatives will begin immediately, even before a Commission order is issued on the Energy Security Improvements. For example, the ISO plans to shortly commence discussions with stakeholders on the interplay between the Forward Reserve Market and the Day-Ahead Ancillary Services.[288] The ISO would like to complete these discussions and file any appropriate Tariff modifications in time for implementation with the FCA 16 cycle.

Other initiatives will require additional time for evaluation. For example, the compliance schedule limited the ISO's ability to fully vet incremental design considerations raised by stakeholders; the ISO anticipates giving stakeholder recommendations further consideration to determine if design improvements are warranted. Finally, as the ISO continues to develop the detailed design's

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[287] *See* ISO-NE Presentation to the NEPOOL Markets Committee, *Energy Security Improvements (ESI): Forward Market Design Update* (Feb. 11-13, 2020), https://www.iso-ne.com/static-assets/documents/2020/02/a4_b_esi_forward_market_design_update.pptx.

[288] *See* Tariff at § III.9.

mathematical formulations, scenario tests and software requirements, it may identify technical enhancements to the Day-Ahead Ancillary Services design.

With a Commission Order no later than November 1st on the rules filed here, the ISO plans to initiate efforts to develop and subsequently present to stakeholders conforming design proposals and corresponding Tariff changes that are necessary to facilitate the Day-Ahead Ancillary Services' implementation. While the ISO will continue to work on scoping, evaluating and developing these elements through the remainder of this year, a Commission Order no later than November 1st will allow for appropriate Tariff changes to be presented in the stakeholder process beginning in 2021 and filed by mid-2022. This schedule is necessary to coordinate the timing of the development of the Tariff rules with the technical software development and implementation work in order to achieve the Energy Security Improvement implementation by June 1, 2024, as discussed in the next section.

C. Software-Related Implementation Activities

The Tariff provisions filed here provide the foundation for key software development and other implementation activities that the ISO will need to complete ahead of the scheduled implementation of the Energy Security Improvements in June 2024. This implementation involves modifying several existing bid-to-bill software systems and building novel capabilities. Some of the affected systems are vendor applications, which will also require coordination between the ISO and the vendor to plan, implement, and test software changes.

As with any implementation effort, the first major phase will be to develop detailed business requirements. Defining and vetting the requirements will require approximately one full year in order to ensure that business requirements are aligned with the market rules and to ensure that the business requirements between various systems are aligned. The second major phase after completing the requirements is implementing the business requirements into the actual software. This phase includes development of technical specifications, coding, application testing, and system-wide integrated testing. The software development phase spans approximately two and a half years. To some extent, the requirements definition and software development phases can happen in parallel for the individual elements of the overall Energy Security Improvements' implementation scope, but the overall timeline will require a full three and a half years ahead of June 2024.

Additionally, the Energy Security Improvements' implementation work must be coordinated with ongoing upgrades to the Day-Ahead Energy Market software. The ISO is two years into a joint effort with its vendor and two other ISOs to replace the existing software platform that was originally developed over 20 years ago. The ISO's vendor required it to update the Day-Ahead Energy Market software system with current technology in order to maintain vendor support for this software that the ISO and Market Participants rely on to clear the market each day. The new software platform will be more robust and capable of supporting the addition of the new Energy Security Improvements' Day-Ahead Ancillary Services in the co-optimized clearing objective. This pre-existing commitment to upgrade the Day-Ahead Energy Market software platform includes the accomplished tasks of completion of the core product and development of the business requirements for the ISO's customizations in the first quarter of 2020. The ISO is currently working with its vendor to schedule delivery of the ISO's customizations for the first half of 2021 for implementation toward the end of 2021. Many of the ISO and vendor resources that are currently occupied with the day-ahead software platform replacement will be needed for the Energy Security Improvements implementation. This overlapping need for resources also contributes to the three and a half year schedule for the Energy Security Improvement design implementation.

The requested effective date of November 1st for the Tariff rules filed here is approximately three and half years before the proposed implementation date for the Energy Security Improvements. A Commission Order on or before that date will provide the ISO with certainty regarding the Energy Security Improvements and time to complete the remaining design elements and Tariff rules before committing significant resources and capital to the Day-Ahead Ancillary Services implementation.

VIII. REQUESTED EFFECTIVE DATE AND COMMISSION ORDER

To facilitate the scheduled implementation of the Energy Security Improvements on June 1, 2024, as reflected in the Tariff rules, the ISO respectfully requests that the Commission issue an order accepting the rules, as filed, and without incorporating the NEPOOL-approved changes, no later than November 1, 2020, to become effective on November 1, 2020, conditioned upon the ISO's filing of an appropriate market power mitigation proposal supported by the ISO's MPA by the fourth quarter of 2021, and the Commission's acceptance of that filing. Commission action by November 1, 2020, will provide the market with much-needed certainty as to the rules that will be in effect for FCA 15. It also will allow adequate time for addressing mitigation and other implementation rules, developing new software and IT systems, and implementing market administration processes in time for June 2024 implementation, all as discussed in Section VII above. Finally, the proposed November 1, 2020 effective date for the rules will facilitate the incorporation of any subsequently-developed revisions to the Energy Security Improvements Day-Ahead Ancillary Services and conforming changes to the proposed rules. It also will avoid eTariff versioning complexities that could be introduced if the rules' effectiveness was deferred to June 1, 2024.

IX. STAKEHOLDER PROCESS

The Tariff provisions filed here reflect three sets of changes: (1) the rules incorporating the Energy Security Improvements; (2) the rules reflecting the early sunset of the Fuel Security Retention Mechanism for FCA 15, conditional upon the Commission's acceptance of the Energy Security Improvements; and (3) the rules to sunset the Inventoried Energy Program for the winter of 2024-2025, which occurs during the FCA 15 Capacity Commitment Period, conditional upon the Commission's acceptance of the Energy Security Improvements. These Tariff rules were considered through the complete NEPOOL Participant Process in three separate motions, as described below.

A. Energy Security Improvements

The Tariff provisions incorporating the Energy Security Improvements were discussed and vetted by the NEPOOL Markets Committee. Following more than a year of discussions over the course of 24 meetings, the Markets Committee, at its March 24, 2020 meeting, considered a motion to recommend that the NEPOOL Participants Committee support the Tariff amendments reflecting the ISO's Energy Security Improvements. At that meeting, the Markets Committee considered a series of amendments to the ISO's Energy Security Improvements, with only one amendment receiving the level of support required to pass. Specifically, the Markets Committee supported an amendment offered by the New England States Committee on Electricity that sought to limit the procurement of RER to the winter months. The once-amended main motion reflecting that amendment did not receive the requisite level of support for a Markets Committee recommendation, with a 51.77% vote in favor. The Markets Committee also failed to support the ISO's un-amended main motion for the Energy Security Improvements by a vote of 42.41% in favor.

The Participants Committee considered the ISO's Energy Security Improvements at its April 2, 2020 meeting. At that meeting, the Participants Committee considered and voted to support three discrete amendments to the ISO's Energy Security Improvements. The amendments, offered by the New England States Committee on Electricity as described in Section V.A of this filing letter, sought to limit the RER to the winter months, remove the accounting for load forecast error, and increase the Option Strike Price. After considering and garnering the requisite support for each amendment, the Participants Committed supported the thrice-amended main motion of the ISO's Energy Security Improvements with the three discrete amendments, by a vote of 61.70% in favor. The Participants Committee also considered the ISO's un-amended Energy Security Improvements. The Participants Committee failed to support the ISO's Energy Security Improvements by a vote of 39.59% in favor.

B. Early Sunset of the Inventoried Energy Program

The proposed revisions to Sections I.2.2 and III.K of the Tariff to sunset the Inventoried Energy Program after the 2023-2024 Capacity Commitment Period, which is one year earlier than permitted under the current Tariff, were presented to the Markets Committee at its March 10-11, 2020 meeting. As discussed in Section VI.B of this filing letter, the ISO's proposal to sunset the Inventoried Energy Program is contingent upon the Commission's acceptance of the Energy Security Improvements for implementation on June 1, 2024. The Tariff rules reflecting the early sunset of the Inventoried Energy Program received the Committee's overwhelming support, with only five oppositions and nine abstentions registered at the March 24 meeting. Subsequent to NEPOOL Markets Committee review, the Participants Committee at its April 2, 2020 meeting overwhelmingly supported the Tariff revisions, with only three abstentions and one opposition.

C. Early Sunset of the Fuel Security Retention Mechanism

The proposed revisions to Sections III.13.2.5.2.5A and III.L of the Tariff to sunset the Fuel Security Retention early for the 2024-2025 Capacity Commitment Period, which is one year earlier than permitted under the current Tariff, were unanimously approved by the Markets Committee at its November 12-13, 2019 meeting, and by the Participants Committee at its December 6, 2019 meeting, as part of its Consent Agenda.[289] The ISO's proposed changes are discussed in Section VI.B of this filing letter.

[289] The Consent Agenda for a NEPOOL Participants Committee meeting, similar to the Consent Agenda for a Commission open meeting, is a group of actions (each recommended by a Technical Committee or subgroup established by the NEPOOL Participants Committee) to be taken by the NEPOOL Participants Committee through approval of a single motion at a meeting. All recommendations voted on as part of the Consent Agenda are deemed to have been voted on individually and independently. In this case, the NEPOOL Participants Committee's approval of the December 6, 2019 Consent Agenda included its support for the Tariff revisions filed herein. Abstentions specifically attributed to the Fuel Security Retention sunset were registered by Exelon Generation Company, LLC and Mr. Michael Kuser.

X. DOCUMENTS ENCLOSED

In support of this filing, the ISO encloses the following for Commission review:

- Transmittal Letter;
- Attachment A – Testimony of Peter T. Brandien;
- Attachment B – Affidavit of Dr. White and the ESI White Paper;
- Attachment C – Affidavit of Dr. Schatzki and the Impact Assessment;
- Attachment D-1 – The ISO's blacklined Tariff sheets;
- Attachment D-2 – The ISO's clean Tariff sheets;
- Attachment E-1 – NEPOOL's blacklined Tariff sheets;
- Attachment E-2 – NEPOOL's clean Tariff sheets; and
- Attachment F – List of governors, utility regulatory agencies in Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island and Vermont, and others to whom a copy of this filing has been e-mailed.

XI. COMMUNICATIONS

In addition to those already identified for service in the official service list for Docket No. EL18-182-000, correspondence and communications regarding this filing should be directed to:

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XII. CONCLUSION

For the foregoing reasons, the ISO respectfully requests that the Commission accept the Tariff rules filed here, without modifications or conditions or incorporation of the NEPOOL amendments, to become effective November 1, 2020, and issue an order by that date.

Respectfully submitted,

By: *Monica Gonzalez*

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Counsel for ISO New England Inc.

CERTIFICATE OF SERVICE

I hereby certify that I have this day served the foregoing document upon each person designated on the official service list compiled by the Secretary in EL18-182-000.

Dated at Holyoke, Massachusetts this 15th day of April 2020.

/s/ Julie Horgan
Julie Horgan
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Attachment A

Testimony of Peter T. Brandien

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

ISO New England Inc.	**)**	**Docket No. EL18-182-___**

TESTIMONY OF PETER T. BRANDIEN
ON BEHALF OF ISO NEW ENGLAND INC.

I. INTRODUCTION AND SUMMARY OF TESTIMONY

Q: PLEASE STATE YOUR NAME, TITLE AND BUSINESS ADDRESS.

A: My name is Peter T. Brandien. I am employed by ISO New England Inc. (the "ISO")[1] as the Vice President of System Operations and Market Administration. My business address is One Sullivan Road, Holyoke, Massachusetts 01040.

Q: PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EXPERIENCE.

A: I have a Bachelor of Science degree in Electrical Engineering from the University of Hartford. I have more than 33 years of energy industry experience in control room operations. I joined the ISO in 2004 as Vice President of System Operations. In that capacity and in my present position, I have been responsible for the day-to-day operations of New England's bulk electric system and oversight of transaction management, transmission technical studies, outage coordination, unit commitment, economic dispatch, system restoration, operator training, certain compliance functions and development of operating procedures. In 2019, I assumed the newly created position of Vice President of System Operations and Market Administration. In this role, I also now have responsibility for administering the New England wholesale energy and ancillary services markets.

Prior to joining the ISO, I spent 17 years at Northeast Utilities, completing my tenure there as director of transmission operations. Before joining Northeast Utilities, I served in the U.S. Navy as a submarine nuclear propulsion plant operator/electrician.

Q: WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A: My testimony explains the operational requirements underlying the ISO's long-term, market-based proposal to address the New England region's energy security problems. The ISO is submitting this proposal, known as the "Energy Security Improvements," to comply with the Federal Energy Regulatory Commission's (the

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1 Capitalized terms used but not otherwise defined in this filing have the meanings ascribed thereto in Section I.2.2 of the ISO-NE Transmission, Markets and Services Tariff (the "Tariff"). Section III of the Tariff contains Market Rule 1, the Standard Market Design ("Market Rule 1").

"Commission") Order of July 2, 2018, in Docket Nos. ER18-1509-000 and EL18-182-000. Specifically, my testimony identifies the operational capabilities and resources the ISO requires in order to comply with national and regional reliability standards and criteria, and thus to ensure that the New England bulk power system is operated within prescribed levels of reliability. My testimony also describes the ISO's current out-of-market approach to ensuring sufficient resources are available to meet operational reliability standards, and explains why that approach has become increasingly problematic.

As I later explain in my testimony, given the region's growing dependence on just-in-time energy resources and its constrained fuel delivery infrastructure,[2] the resources that the ISO is counting on for forecast-load balances, operating reserves, and replacement energy capabilities may not have the underlying energy supply needed to operate in real-time if called. If the system experiences an unexpected, extended loss of a large supply source, particularly during stressed system conditions, such as an extended cold period, the region may not have the energy necessary to reliably fill the resulting energy gap. This, in turn, could result in violations of mandatory reliability standards. Therefore, it is appropriate and advisable to eliminate out-of-market processes and instead establish new market mechanisms to create incentives for participants to make the investments in energy supply needed to ensure the power system's reliability.

Q: PLEASE SUMMARIZE THE OPERATIONAL CONTEXT FOR THE ENERGY SECURITY IMPROVEMENTS.

A: The ISO is registered with the North American Electric Reliability Corporation ("NERC") as the Reliability Coordinator, the Balancing Authority, and the Transmission Operator for the New England region. Among its responsibilities in those roles is the obligation to prepare an Operating Plan[3] each day for the following

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[2] *See* Pet. of ISO New England Inc. for Waiver of Tariff Provisions, Exhibit ISO-1 at, *ISO New England Inc.*, Docket No. ER18-1509-000 (May 1, 2018) (describing the New England region's constrained fuel infrastructure and growing dependence on just-in-time energy sources).

[3] *See* Glossary of Terms Used in NERC Reliability Standards ("NERC Glossary of Terms"), https://www.nerc.com/pa/Stand/Glossary%20of%20Terms/Glossary_of_Terms.pdf.

day's system operations. Each day's Operating Plan must conform to applicable reliability standards and criteria of NERC and the Northeast Power Coordinating Council ("NPCC"), as well as with the ISO's Operating Procedures (for the sake of brevity I will refer to these standards, criteria and procedures collectively as "reliability standards").

The ISO depends on the diverse range of operational capabilities of the region's resources, above and beyond their day-ahead energy schedules, to develop a sound Operating Plan for each day. Each next-day Operating Plan must include resources to supply replacement energy when contingencies occur (*e.g.*, unplanned outages of equipment), or additional energy when increases in demand put the system under stress. Reliable operations may require that energy be provided from resources (various categories of "reserves," as I will describe below) that were not otherwise committed in the Day-Ahead Energy Market ("Day-Ahead Market"), and/or in excess of committed resources' day-ahead scheduled quantities of energy. In this context, "reserves" refers generally to the capability to provide energy upon request, and not to real-time operating reserves.

At present, the ISO does not specifically assign or efficiently compensate resources in the Day-Ahead Market for all of the operational capabilities that are necessary to ensure a reliable next-day Operating Plan. This out-of-market approach was sufficient in the past. Historically, for the development of its next-day Operating Plans, the ISO had been able to rely upon offline or partly unloaded, online resources with on-site fuel supplies such as coal or oil to provide replacement energy when called upon. However, ongoing industry trends are increasingly challenging the reliability of the New England power system.

Specifically, more and more of the older resources with readily available fuel supplies (those upon which the ISO has historically relied for the capabilities needed for secure next-day Operating Plans) are ceasing to operate. These resources are being replaced with natural gas-fired generators that rely on as-available fuel supply arrangements, and with renewable resources whose energy production capability is intermittent. Initially, the ISO approached this decline in available, unloaded generation capacity with stored input energy as a *<u>fuel</u>* security concern. However, the issue fundamentally is the security of a reliable supply of *<u>electric energy</u>*, *i.e.*, of ensuring the system has sufficient energy and *__energy reserves__* to maintain reliable service consistent with prescribed reliability standards. The ISO thus now faces the task of developing daily Operating Plans that are sufficient to satisfy the various operational requirements of the New England bulk power system with a generation fleet that is transitioning to fewer and fewer resources that can provide, on demand, the operational capabilities the ISO requires to satisfy those standards.

The purpose of the Energy Security Improvements, therefore, is to provide, as the transformation of the generation fleet continues, clear and transparent market incentives for the development of sufficient resources in New England that can sustainably provide the operational capabilities that are necessary to ensure the reliable operation of the New England bulk power system each Operating Day. This testimony explains the types and amounts of reserves that the ISO requires to comply with applicable reliability standards. Dr. Matthew White, Chief Economist of the ISO, describes in the white paper entitled "Energy Security: Creating Energy Options for New England" (the "ESI White Paper") that he submits today along with my testimony the new ancillary services the ISO proposes as part of the Energy Security Improvements. Dr. White also explains how the new ancillary services will better enable the New England wholesale energy market to incent resources to develop the operational capabilities needed to provide sufficient reserves of energy to meet reliability requirements.

Q: HOW IS YOUR TESTIMONY ORGANIZED?

A: The remainder of this testimony is organized as follows:

In Section II, I review the reliability standards with which the ISO must comply, and which are the foundation for the proposed new Day-Ahead Ancillary Services described in the ESI White Paper.

Section III describes the ISO's current approach for ensuring sufficient resources are available to meet applicable reliability requirements.

In Section IV, I describe the energy security concern in New England, and explain why the ongoing evolution of the New England electric system to one powered largely by just-in-time energy resources makes it infeasible for the ISO to continue to rely on its present, out-of-market approach to obtaining sufficient resources to provide the energy reserves necessary to ensure reliable operation of the system.

Finally, in Section V, I explain how the proposed new Day-Ahead Ancillary Services align with the ISO's needs to ensure compliance with applicable reliability standards.

II. <u>MANDATORY RELIABILITY STANDARDS TO WHICH THE ISO's DAILY OPERATING PLANS MUST CONFORM</u>

Q: WHAT ARE THE RELIABILITY STANDARDS REQUIRING THE DEVELOPMENT OF OPERATING PLANS AND WHAT IS THE BASIS FOR THOSE PLANS?

A: NERC reliability standards require the ISO, as the Balancing Authority for the New England Balancing Authority Area, to develop next-day Operating Plans that ensure the availability of sufficient resources to meet expected energy demand (load) and reserve requirements. Specifically, Requirement R4 of NERC-TOP-002-4 – Operations Planning, requires each Balancing Authority to have an Operating Plan for next-day operations that addresses each of the following criteria: expected generation resource commitment and dispatch, interchange scheduling, demand (load) patterns, and capacity and energy reserve requirements. In this context, an Operating Plan refers to:

> processes and procedures which are available to the System Operator on a daily basis to allow the System Operator to reliably address conditions which may arise throughout the day. It is valid for tomorrow, the day after, and the day after that.[4]

Consistent with this standard, the ISO develops Operating Plans to ensure the availability of sufficient resources with the physical capability to meet various criteria and objectives.

In the context of these standards, the term "reserves" encompasses a number of different requirements, functions, and purposes within the time horizon of a Balancing Authority's Operating Plans. The NERC Glossary of Terms defines "Operating Reserve"

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[4] NERC-TOP-002-4, Section F (Associated Documents).

as "that capability above firm system demand required to provide for regulation, load forecasting error, equipment forced and scheduled outages[,] and local area protection."

Ensuring the availability of sufficient resources that possess the physical capability to satisfy energy and reserve requirements is a critical component of the ISO's Operating Plans. The ISO must be able to rely on these resources to assist in the prompt restoration of the supply-demand balance on the system following an unexpected loss of one or more large sources of energy ("source-loss" contingencies).

Q: PLEASE DESCRIBE THE TYPES AND AMOUNTS OF RESERVES THE ISO NEEDS TO COMPLY WITH APPLICABLE RELIABILITY STANDARDS.

A: Taken together, the reliability standards with which the ISO must comply establish three specific types of reserves (collectively, "Operating Reserve") and minimum quantities for each type. The ISO must incorporate these reserves into its Operating Plans.

Operating Reserve comprises Ten-Minute Spinning Reserve (equivalent to the "synchronized" reserve described in NPCC criteria), Ten-Minute Reserve, and Thirty-Minute Operating Reserve. The minimum required amount for each type of Operating Reserve is determined by the system's first and second largest source-loss contingencies. Ten-Minute Reserve and Ten-Minute Spinning Reserve requirements are adjusted for historical non-performance of designated reserves.

The ISO is responsible for identifying the First Contingency Loss and the Second Contingency Loss. As defined in ISO New England Operating Procedure No. 8 – Operating Reserve and Regulation, [5] the First Contingency Loss is "the largest capability outage (MW) that would result from the loss of a single element," *i.e.*, a generator or an importing transmission element or resource. The Second Contingency Loss is loss of the second largest single source of power (*i.e.*, the largest single source remaining after the First Contingency Loss) included in the applicable Operating Plan.

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[5] *See* ISO New England Operating Procedures No. 8 – Operating Reserve and Regulation ("Operating Procedures No. 8"), https://www.iso-ne.com/static-assets/documents/rules_proceds/operating/isone/op8/op8_rto_final.pdf.

The following is a summary of the reliability standards that specify the requirements for Operating Reserve that the ISO must incorporate into its Operating Plans:

1) NERC BAL-002-3 (Disturbance Control Standard) – Contingency Reserve for Recovery from a Balancing Contingency Event, Requirement R.1. This NERC standard requires the ISO, as the Balancing Authority, to maintain and activate Contingency Reserve to respond to all Reportable Balancing Contingency Events[6] in order to restore the Area Control Error ("ACE")[7] of the Balancing Authority Area within prescribed time limits. ACE is a measurement that describes the instantaneous difference between the transfer of actual and scheduled interchange between two Balancing Authority Areas (accounting for the effects of frequency bias and correction for meter error). When there is a deviation in ACE caused by the loss of energy supply meeting the criteria of a Reportable Balancing Contingency Event, the Balancing Authority must restore ACE to a defined value within 15 minutes following the event. This 15-minute interval is "the Contingency Event Recovery Period."

In this context, Contingency Reserve is NERC's term for the reserve capacity that may be dispatched to supply energy (*i.e.,* "activated" or "deployed") by the Balancing Authority to respond to a source-loss contingency. As discussed further below, the NPCC's and the ISO's required Ten-Minute Reserve meets this NERC requirement to restore ACE. NERC BAL-002-3, Requirement R.2, requires the ISO (again, as the Balancing Authority) to include in its Operating Plan a process "to determine the Most Severe Single Contingency and make preparations to have Contingency Reserve equal to, or greater than . . . the Most Severe Single Contingency available for maintaining system reliability."

2) NPCC Regional Reliability Reference Directory #5 (Reserve) establishes specific minimum requirements for certain types and amounts of reserves. These include:

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6 *See* NERC Glossary of Terms.

7 *See id*.

- Ten-Minute Reserve. Under Requirement R1, "[e]ach Balancing Authority shall have ten-minute reserve available to it that is at least equal to its first contingency loss." Ten-minute reserve meets the requirement for Contingency Reserve under the NERC standards. Here, "first contingency loss" again refers to the most severe single source-loss contingency.
- Thirty-Minute Reserve. Under Requirement R2, "[e]ach Balancing Authority shall have thirty-minute reserve available to it that is at least equal to one-half its second contingency loss." Thirty-minute reserve is the sum of synchronized and non-synchronized reserve that can supply energy to the bulk power system within thirty minutes, excluding capacity assigned to ten-minute reserve.
- Ten-Minute Synchronized Reserve. Requirement R4 requires that a portion of the ten-minute reserve must be synchronized reserve. The maximum required amount of synchronized reserve "shall be 100 percent of its ten-minute reserve," and the minimum requirement "shall be 25 percent of its ten-minute reserve," with the actual level adjusted for historical non-performance of designated reserves.

Requirement R6 of NPCC Directory #5 also prescribes that "synchronized reserve, ten-minute reserve, and thirty-minute reserve available to a Balancing Authority, if activated, shall be sustainable for at least one hour from the time of activation."

3) ISO New England Operating Procedure No. 8 establishes the ISO's criteria for meeting the prescribed levels of synchronized and non-synchronized reserve under NPCC Directory #5. Specifically:

- Part III.I.A provides that the "ISO shall maintain a quantity of Ten-Minute Reserve at least equal to the amount required to replace the First Contingency Loss in the New England RCA/BAA [(Reliability Control Area/Balancing Authority Area)]." To take account of historical non-performance of reserves, the ISO currently maintains a minimum Ten-Minute Reserve equal to at least 120 percent of the First Contingency Loss. Non-performance has resulted in a Ten-Minute Reserve requirement in the range of 120-125 percent of the First Contingency Loss.
- Part III.I.A.1 provides that "[o]ne hundred percent (100%) of the New England RCA/BAA Ten-Minute Reserve Requirement shall be synchronized reserve except as described [in OP-8]." The ISO typically sets the Ten-Minute Spinning Reserve

requirement between 31 percent and 50 percent of the Ten-Minute Reserve requirement. System Operators may adjust this amount as needed based on system conditions.

- Part III.I.B provides that the "ISO shall maintain a quantity of [Thirty-Minute Operating Reserve] at least equal to fifty percent (50%) of the Second Contingency Loss." Parts III.1.B and IV of OP-8 establish that Thirty-Minute Operating Reserve can be used to help the system replenish the loss of, and thereafter maintain, Ten-Minute Reserve.

It is also important to note that both NERC and NPCC anticipate that a Balancing Authority's forward-looking load forecasts are subject to error, and expect the use of Operating Reserves to address such forecasting error. Requirement R.4 of NERC-TOP-002-4 stipulates that a Balancing Authority's Operating Plan must balance "expected generation resource commitment and dispatch," "interchange scheduling," and "demand patterns." NERC's Glossary of Terms provides that, among other purposes, reserves include "[t]he capability above firm system demand required to provide for … load forecasting error." Although the standards provide for committing reserves to address errors in load forecasting, they do not associate a particular type of reserves with that factor. Nor do they state the magnitude of potential forecast error that a Balancing Authority should consider in developing its Operating Plans. Currently, the ISO relies on Operating Reserve to help account for load forecast error.

Q: ARE THERE RELIABILITY STANDARDS THAT DEFINE REQUIREMENTS FOR RESERVE RESTORATION FOLLOWING A CONTINGENCY OR OTHER UNANTICIPATED EVENTS?

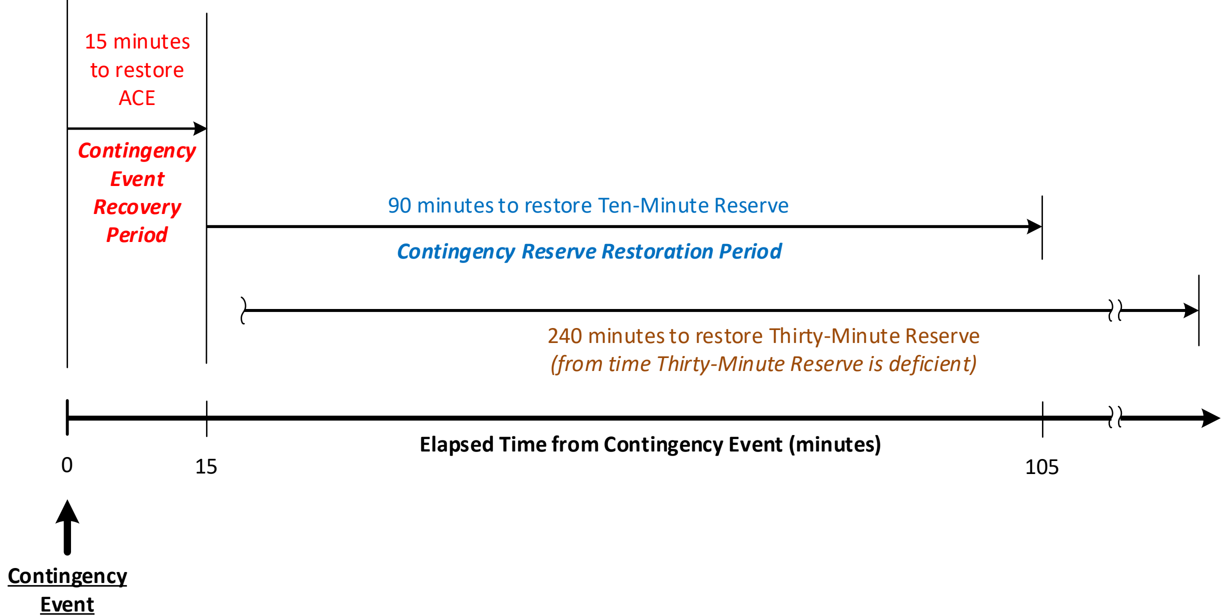
A: Yes. NERC and NPCC criteria also establish timeframes within which Operating Reserve must be *restored* after it is converted to energy to respond to a contingency or other unanticipated events. Thus, not only must the ISO's next-day Operating Plan provide sufficient capability to respond to a contingency within prescribed time limits, it must also include, within stated time limits, sufficient capability to replace the energy initially provided by resources supplying Contingency Reserve (*i.e.*, Ten-Minute Reserve) and

Thirty-Minute Operating Reserve, in order to restore the system's reserves to a "normal" state.

Requirement R.3 of NERC-BAL-002-3 requires the Balancing Authority to "restore its Contingency Reserve to at least its Most Severe Single Contingency" ninety minutes following the end of the Contingency Event Recovery Period. NPCC Directory #5 expands on this requirement. It states that "[i]f a Balancing Authority becomes deficient in ten-minute reserve or forecasts a deficiency, it shall restore its ten-minute reserve as soon as possible and within the duration specified in the appropriate NERC standard." This means that the Balancing Authority must restore its Ten-Minute Reserve to the minimum required amount within ninety minutes after the reserve becomes deficient (or within ninety minutes following the end of the Contingency Event Recovery Period, if the deficiency results from deploying Ten-Minute Reserve following a Reportable Balancing Contingency Event). If the Ten-Minute Reserve is deficient following the First Contingency Loss, then the amount that must be restored is determined by the magnitude of the next (*i.e.*, post-contingency) largest source of supply, which normally equals the Second Contingency Loss (as determined pre-contingency). The deployment of Thirty-Minute Operating Reserves provides energy to replace some of the energy obtained initially from Ten-Minute Reserves. NPCC Directory #5 also prescribes a restoration time for Thirty-Minute Operating Reserve: "A Balancing Authority deficient in thirty-minute reserve for four hours . . . shall eliminate the deficiency if possible, or minimize the magnitude and duration of the deficiency." If the Thirty-Minute Operating Reserve is deficient, then the amount that must be restored is determined by one-half the magnitude of the second largest source of supply (post-contingency), which normally equals the third contingency loss (as determined pre-contingency).

Figure 1 below depicts the timelines for deploying reserves to respond to a supply contingency, and for restoring those reserves.

Figure 1



To summarize, following a source-loss contingency and the recovery of ACE (within 15 minutes), the ISO must restore the system's Ten-Minute Reserve and Thirty-Operating Minute Reserve within prescribed time limits if they are deficient. This means that, within ninety minutes following a source-loss contingency, the ISO must be able to obtain sufficient energy to replace the energy loss from the initial contingency, *and* must restore the minimum required Ten-Minute Reserve. Restoring the Ten-Minute Reserve to a non-energy producing status may also require the procurement of energy, as resources may be backed down to again provide reserves, and must be replaced. In addition, if the deployment of resources to replace the source loss or restore Ten-Minute Reserve results in a deficiency of Thirty-Minute Operating Reserve, the ISO must also obtain *additional* energy from other resources to restore those reserves.

Q: PLEASE PROVIDE AN EXAMPLE THAT SHOWS HOW THESE VARIOUS RESERVE REQUIREMENTS ARE DETERMINED IN PRACTICE.

A: The following numerical example should help to illustrate, conceptually, the amounts of replacement *energy* the ISO needs to restore reserves after a contingency loss and the timelines for accomplishing such replacements. **Table 1** below reflects the day-ahead scheduled energy output of the three hypothetical supply resources used in the example. These resources comprise the system's largest potential contingency losses during the Operating Day. The table also indicates the corresponding requirements for Ten-Minute Reserve and Total Reserve based on these potential source losses. For purposes of this conceptual example only, I use the term "Total Reserve" requirement to refer to the sum of the Ten-Minute Reserve and Thirty-Minute Operating Reserve.[8]

Table 1

	Resource	**MW**
Pre-Contingency		
First Contingency Loss	Resource A	1600
Second Contingency Loss	Resource B	1400
Ten-Minute Reserve		1600
Thirty-Minute Operating Reserve		700
Total Reserve Requirement		2300
Post-Contingency		
First Contingency Loss	Resource B	1400
Second Contingency Loss	Resource C	1300
Ten-Minute Reserve		1400
Thirty-Minute Operating Reserve		650
Total Reserve Requirement		2050

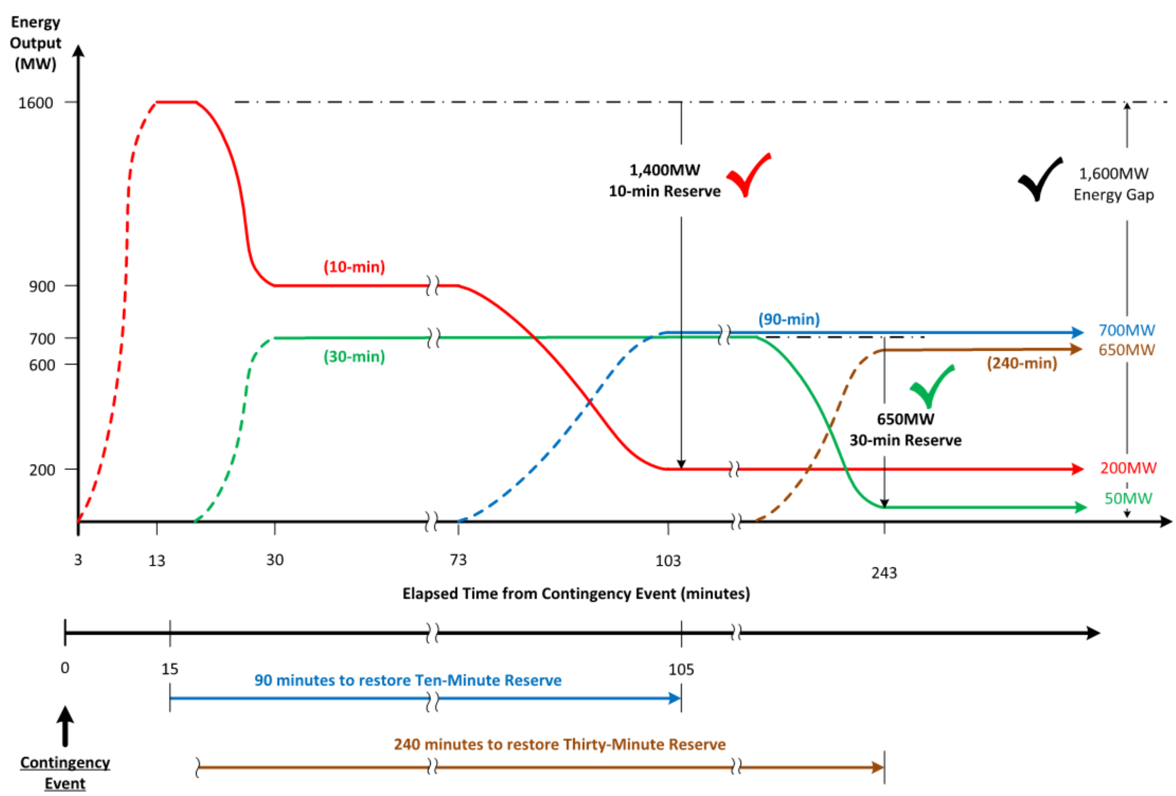
For simplicity, this conceptual example assumes that the reserve requirements are set exactly equal to the size (in MW) of the potential source-losses (*i.e.*, the example disregards ISO operating procedures that adjust required reserve amounts for historical

8 For clarity, "Total Reserve" requirement as used in this testimony does not refer to Tariff-defined "Total Reserve Requirement" for real-time operating reserves, which also include real-time "Replacement Reserve."

non-performance) and assumes load is constant. The example further assumes that, prior to the contingency, the Ten-Minute Reserve and Total Reserve requirements are exactly satisfied with no surplus (*i.e.*, resources are able to provide exactly 1600 MW of Ten-Minute Reserve, and resources are able to provide exactly 700 MW of Thirty-Minute Operating Reserve, resulting in 2300 MW of Total Reserve).

Figure 2 below illustrates the deployment of reserves in this example following the assumed loss of Resource A (the pre-contingency First Contingency Loss), and the restoration of those reserves within prescribed time limits.

Figure 2



The following sequence of events illustrates what would transpire during the Operating Day after the First Contingency Loss occurred, given the assumed conditions.

- First Contingency Resource (Resource A) trips, resulting in a 1600 MW energy loss.

- In response to the contingency, as depicted by the red line in Figure 2, the ISO commits and dispatches the entire 1600 MW of Ten-Minute Reserve, thus deploying these resources to supply energy.
- System supply and demand balance (*i.e.*, the energy gap) is recovered within 15 minutes of the contingency (in accordance with NERC BAL-002-3).

- First and Second Contingency Loss values are updated to post-contingency values.
  - The new (post-contingency) Ten-Minute Reserve requirement is 1400 MW, equal to the energy output of Resource B.
  - The new (post-contingency) Total Reserve requirement is 2050 MW, reflecting, in addition to the Ten-Minute Reserve requirement above, one-half of the energy output of Resource C (650 MW).
- As a result of the activation of the Ten-Minute Reserve resources following the loss of Resource A, the Ten-Minute Reserve is depleted.
  - The system's supply of Ten-Minute Reserve must be restored (to the new required minimum of 1400 MW) within ninety minutes following the Contingency Event Recovery Period (as required by NERC BAL-002-3).
  - The ISO's commitment and dispatch of Thirty-Minute Operating Reserve resources after the loss of Resource A supplies 700 MW of additional energy within thirty minutes, as depicted by the green line in Figure 2.
  - Activation of the 700 MW of Thirty-Minute Operating Reserve to supply energy permits the ISO to back down 700 MW of Ten-Minute Reserve, thereby restoring one-half of the post-contingency Ten-Minute Reserve requirement (which is now 1400 MW).
- Accordingly, the ISO must obtain 700 MW of replacement energy within ninety minutes to satisfy the post-contingency Ten-Minute Reserve restoration requirement. In this example, the 700 MW of replacement energy allows for 700MW of the still deployed Ten-Minute Reserve resources to be restored to a reserve (non-energy producing) status.
  - This replacement energy would come from a combination of additional resources that can deliver energy within ninety minutes, and/or from resources already online which have previously unloaded ninety-minute ramping capability. (This replacement capability is not shown in the assumptions table above.)
  - In this example, with the supply of energy from these additional resources (as depicted by the blue line in Figure 2), the ISO can, within ninety

minutes, back down 700 MW of the 900 MW of the pre-contingency Ten-Minute Reserve that continued to run following activation of the Thirty-Operating Minute Reserve. The Ten-Minute Reserve thus is restored to the post-contingency requirement of 1400 MW (in this example, 200 MW of the pre-contingency Ten-Minute Reserve continues to run to replace a portion of the 1600 MW lost when Resource A tripped).

- As a result of the activation of the Thirty-Minute Operating Reserve resources following the loss of Resource A, the system remains deficient of its Total Reserve Requirement.
- Accordingly, the ISO must obtain 650 MW of replacement energy to satisfy the post-contingency Total Reserve requirement within four hours (240 minutes) of becoming deficient (per NPCC Directory #5). In this example, the 650 MW of replacement energy allows for 650 MW of the still deployed Thirty-Minute Operating Reserve resources to be restored to a reserve (non-energy producing) status.
    - This replacement energy would come from a combination of additional resources that, within 240 minutes, can deliver energy in excess of any capability contributing to the ninety-minute replacement of Ten-Minute Reserve, and/or from resources already online which have previously unloaded 240-minute ramping capability in excess of any capability contributing to the ninety-minute replacement of Ten-Minute Reserve. (Again, this replacement energy is not shown in the assumptions table above.)
    - In this example, with the supply of energy from these additional resources (as depicted by the brown line in Figure 2), the ISO can, within 240 minutes, back down 650 MW of the 700 MW of previously activated, pre-contingency Thirty-Minute Operating Reserve. The Total Reserve requirement is thus restored to the post-contingency requirement of 2050 MW (and, in this example, 50 MW of the pre-contingency Thirty-Minute Operating Reserve continues to run to replace a portion of the 1600 MW lost when Resource A tripped).

In this example, deploying the Thirty-Minute Operating Reserve restores one-half of the Ten-Minute Reserve needed to satisfy the post-contingency Ten-Minute Reserve requirement, which must be satisfied within ninety minutes following restoration of ACE. The replacement energy needed to restore the other half of Ten-Minute Reserve must come from resource capabilities *other than* (a) the activated Thirty-Minute Operating Reserve and (b) the previously restored, 700 MW of Ten-Minute Reserve. Accordingly, the ISO's next-day Operating Plan must provide for the capability to obtain, within ninety minutes, replacement energy in an amount equal to one-half of the pre-contingency second largest supply source; in this example, 700 MW of replacement energy.

In this example, the next-day Operating Plan also must provide for the capability to obtain, within four hours, enough replacement energy to restore enough Thirty-Minute Operating Reserve to a reserve (non-energy producing) status in order to satisfy the post-contingency Total Reserve requirement. This replacement energy must come from resource capabilities *other than* those providing the replacement energy that allows the Ten-Minute Reserve to be restored. Here, the amount of replacement energy needed is equal to one-half of the post-contingency second largest supply source; in this example, Resource C, which is the pre-contingency third largest supply loss or an additional 650 MW of replacement energy.

III. <u>THE ISO'S CURRENT APPROACH TO COMPLYING WITH RESERVE REQUIREMENTS</u>

Q: WHAT ARE THE CAPABILITIES THAT THE ISO NEEDS TO ENSURE ITS NEXT-DAY OPERATING PLANS MEET THE RELIABILITY STANDARDS AND CRITERIA YOU HAVE DESCRIBED?

A: The ISO relies on available resources' capabilities, above and beyond their day-ahead energy schedules, that fall into three broad operational categories:

1. capability to provide energy to cover any energy gap when the total energy supply cleared in the Day-Ahead Market from physical resources (*e.g.*, generation and net imports into New England) is insufficient to serve the forecast electricity demand for the next Operating Day;
2. capability to provide fast-start/fast-ramping generation contingency response, which enables the system to promptly restore the gap between energy supply and demand following an unanticipated supply loss (consistent with the timeframes established in applicable reliability standards); and

3. capability to provide replacement energy, for the balance of the Operating Day, when and as needed, to restore contingency reserve resources to reserve status and to serve an unanticipated increase in demand.

These capabilities comprise three essential reliability services that the ISO relies on in its Operating Plans to meet the reliability standards I have described.

Q: HOW DOES THE ISO DEVELOP ITS OPERATING PLANS TO MEET THE RELIABILITY STANDARDS AND CRITERIA YOU HAVE DESCRIBED?

A: The ISO's processes for ensuring sufficient resources are available to meet hourly load and reserve requirements for the next Operating Day are documented in the Market Rules (Section III of the Tariff) and in System Operating Procedure (SOP)-RTMKTS.0050.0010 – Perform Reserve Adequacy Assessment.

Section III.1.10.1(d) of the Tariff is the foundation for the ISO's day-ahead scheduling:

> Scheduling encompasses the Day-Ahead and hourly scheduling process, through which the ISO determines the Day-Ahead Energy Market schedule and determines, based on changing forecasts of conditions and actions by Market Participants and system constraints, a plan to serve the hourly energy and reserve requirements of the New England Control Area.

As detailed in SOP-RTMKTS.0050.0010, after the Day-Ahead Market clears, the ISO performs day-before and intra-day Reserve Adequacy Analysis ("RAA")[9] and, if

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[9] The Tariff defines the Reserve Adequacy Analysis as "the analysis performed by the ISO to determine if adequate Resources are committed to meet forecasted load, Operating Reserve, and security constraint requirements for the current and next Operating Day." In the System Operating Procedure, this analysis is referred to as "Reserve Adequacy Assessment." *See* SOP-RTMKTS.0050.0010 - Perform Reserve Adequacy Assessment, https://www.iso-ne.com/static-assets/documents/rules_proceds/operating/sysop/rt_mkts/sop_rtmkts_0050_0010.pdf.

necessary, then commits additional resources to meet each hour's forecast energy (load) and reserve requirements through these out-of-market processes.[10]

Presently, the Day-Ahead Market does not incorporate the ISO's forecast of next-day energy demand (load). To provide for the required Operating Reserve capabilities as part of its Operating Plan, the ISO, after the Day-Ahead Market is cleared, (a) determines the projected Operating Reserve requirements for each hour of the next Operating Day; (b) assesses the projected supply of each type of reserves for each hour; and (c) if necessary, commits additional resources—out of market—through re-dispatch of day-ahead committed resources (and potentially, but very rarely, supplemental commitments) to meet each hour's projected Operating Reserve requirements. These assessments and actions are performed as part of the RAA process, conducted after the Day-Ahead Market clearing is complete.

In addition, the ISO performs Security Constrained Reserve Adequacy ("SCRA") analyses at pre-determined schedules and as required based on updated information regarding forecast load, resource availability, and transmission system operations. The SCRA is a security-constrained dispatch of the resources previously committed to ensure that those resources can be utilized to meet Operating Reserve requirements (*i.e.*, are not transmission constrained). If this analysis shows that any such resources are constrained, the ISO determines whether and what additional or different resource commitments may be necessary.

Q: HOW DOES THE RAA PROCESS RELATE TO DAY-AHEAD MARKET OUTCOMES?

A: The ISO normally performs the initial RAA each day after the close of the Re-Offer Period. The ISO completes additional, intra-day RAAs based on updated forecasts of load, resource availability, and transmission system information.

The principal focus of the initial RAA is to review the difference between:

(1) the ISO's forecast energy (load) plus reserve requirements, and

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10 In real-time, the ISO can initiate special procedures with neighboring control areas in certain post-contingency situations to speed recovery from a large source loss contingency, including Simultaneous Activation of Ten-Minute Reserve and other emergency procedures. However, consistent with NPCC criteria and the ISO's coordination agreements, the ISO does not rely upon these special procedures to satisfy its reserve requirements in its next-day Operating Plans.

(2) the total (physical) resources and (net) imports that cleared in the Day-Ahead Market.

This difference is the primary consideration in identifying any additional actions (*e.g.*, resource commitments) necessary to ensure a reliable, next-day Operating Plan. After the Day-Ahead Market clears, there is often an excess of supply capability available to meet the ISO's day-ahead energy forecast (load). This excess supply capability is comprised of:

- Resources (other than fast-start and intermittent power resources) with day-ahead commitment schedules *and* with Day-Ahead Market energy schedules below their maximum output (or maximum reduction, in the case of demand response) (in other words, the excess capability, or headroom, of day-ahead scheduled resources);
- Forecast energy production of intermittent resources in excess of their Day-Ahead Market cleared energy; and
- Fast start resources, which are available in real-time with or without a Day-Ahead Market commitment schedule.

The ISO relies upon this capability in excess of the day-ahead scheduled energy for the reserves it requires for its day-ahead Operating Plan.

In the RAA process, the ISO assesses if the total capabilities of all physical supply resources committed in the Day-Ahead Market and the available fast-start resources can satisfy the forecast energy (load) plus reserve requirements for each hour. If the total committed capabilities and available fast-start resources are less than the requirements, the RAA optimization tools will indicate which additional resources are most cost-effective to commit to meet the system's reliability requirements, and the ISO then commits those resources (again, this occurs out of market—the Day-Ahead Market is cleared before the RAA process is completed).

On the demand side, the inputs to the RAA process are the ISO's forecast hourly load and required Operating Reserves. Bid-in, day-ahead energy demand is not considered in the RAA. The supply inputs to the RAA are the resources comprising the excess supply capability listed earlier in this response.

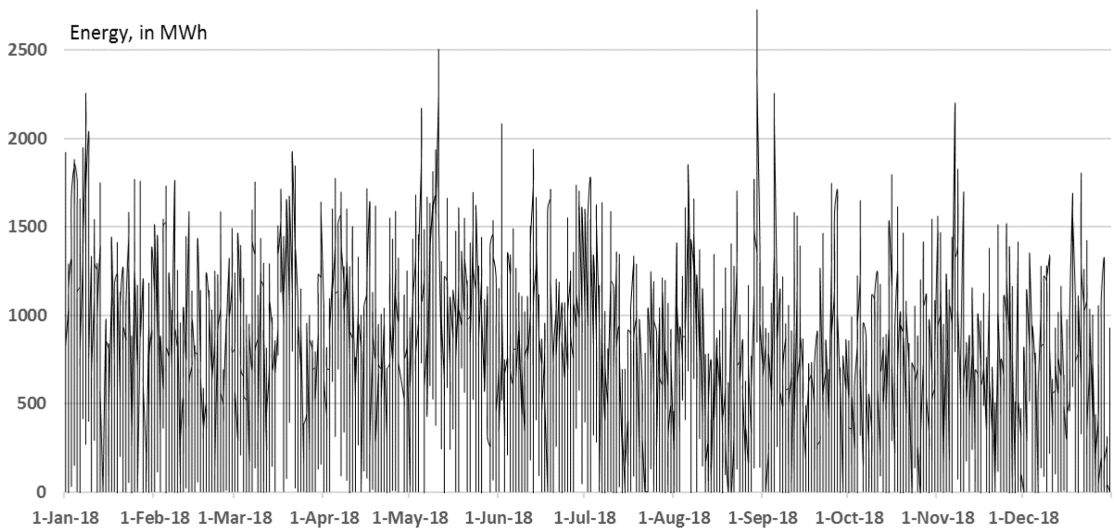
The RAA includes a commitment evaluation which ensures that the available supply will satisfy the load forecast and reserve requirements in each hour. This is accomplished by a second optimization (the first is the Day-Ahead Market) of commitment and dispatch. Based on this analysis, the ISO may: "dispatch up" an already-committed resource to an amount greater than the unit's day-ahead commitment schedule; extend the run-time of a resource with a day-ahead commitment schedule; and/or schedule additional resources (a "supplemental commitment" of a resource that does not otherwise have a day-ahead commitment schedule). *Notably, these are all out-of-market actions. Thus, the associated costs are not reflected in Day-Ahead Market prices.*

Q: WHAT IS THE MAGNITUDE OF ENERGY THE ISO RELIES ON TO SATISFY THESE OPERATIONAL REQUIREMENTS?

A: The particular resources and the total amount of reserve capability that the ISO relies on to satisfy operational requirements vary by day and by hour. The resources the ISO may call on to meet operational needs vary based on a number of factors, such as: the day-ahead cleared generation pattern, the cleared and forecasted demand profile over the course of the day, available resources' capabilities and lead-times, intermittent resources' energy production (actual versus forecast), constraints on the interstate gas pipelines that supply electric generation, etc. The energy reserves needed to address a load-energy imbalance can vary daily from none in some hours to more than a gigawatt in other hours. **Figure 3** below, previously presented at the June 2019 NEPOOL Markets Committee meeting[11] and based on analysis of the approved, next-day Operating Plans for each day of 2018, shows that the amounts of energy required to balance forecast energy supply with energy demand can vary significantly from day to day and often within a day. During the year depicted in this graph, the quantity of required energy for balancing was zero in approximately 22 percent of hours in 2018, the median hourly requirement was approximately 460 MWh, and the maximum hourly requirement was approximately 2,728 MWh on September 3, 2018.

[11] *See* ISO Presentation to NEPOOL Markets Committee, *Energy Security Improvements: Market-Based Approaches*, June 10-12, 2019 at 31 and 109, https://www.iso-ne.com/static-assets/documents/2019/06/a2a_iso_presentation_energy_security_improvements_market_based_approaches.pptx.

Figure 3



The total hourly operating reserves required for contingency response may range from 2 to 2.5 gigawatts, depending upon the projected size of the first and second largest source-loss contingencies each day. The specific amounts required for the peak hour of each Operating Day are reported daily in the ISO's Morning Report.[12]

The amount of required replacement energy depends on the scheduled energy profile of the system's largest contingency over the course of the day, but rarely exceeds approximately 1.3 GW. This can vary hour to hour if the largest contingency, for example, is an external interface with an hourly-varying import energy schedule for the next day. Alternatively, the largest contingency may be constant over the course of the day if it is a fully loaded resource with constant scheduled power output over time (*e.g.*, a nuclear generating resource)

Q: CAN YOU ELABORATE ON THE CONDITIONS OF SEPTEMBER 3, 2018 THAT RESULTED IN THE ENERGY GAP OF AS MUCH AS 2,728 MWH?

A: The system conditions of September 3, 2018 and resulting Capacity Scarcity Conditions provide an example of how the ISO relies on resources' collective reserve capabilities

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[12] See https://www.iso-ne.com/markets-operations/system-forecast-status/morning-report.

to reliably serve the region's electricity demand. On this particular day, two primary factors, significant generation outages/reductions and significant deviations of demand from the load forecast (caused, in turn, by weather forecast error), led the ISO to invoke ISO Operating Procedure #4, Actions in a Capacity Deficiency.

The Operating Plan for the September 3 Operating Day indicated significant Operating Reserve surplus based on expected resource availability and load forecast. During the course of the operating day, the system experienced approximately 1,900 MW of resource outages and energy supply reductions (including a single resource outage of approximately 1,050 MW). Numerous out-of-market resource commitments were made throughout the day in an attempt to replace the lost energy. In addition, the weather on September 3 was significantly warmer and more humid than was originally forecasted, resulting in an actual peak load of 22,956 MW, approximately 2,400 MW, or more than 11.5 percent, higher than the forecasted peak load of 20,590 MW. This example shows that the need for energy reserves can arise at any time of year, and is not strictly a winter need.

IV. <u>INADEQUACY OF THE ISO'S CURRENT APPROACH FOR MEETING RESERVE REQUIREMENTS</u>

Q: WHAT ARE YOUR CONCERNS WITH THE ISO'S CURRENT METHODOLOGY FOR ENSURING RELIABILITY THROUGH ITS NEXT-DAY OPERATING PLANS?

A: Industry and policy trends are changing the makeup of New England's power system. The region's resource adequacy requirement for *capacity* is based on expected summer peak demand, and is consistently satisfied. However, the region's principal challenge is assuring that the system's resources, regardless of fuel or technology, are able to meet the demand for electricity and required Operating Reserves throughout the year. This is a matter of *<u>energy</u>* security, *i.e.*, there may be insufficient energy available to the power system to withstand an unexpected, extended large generation or supply loss, particularly during cold weather conditions. Simply put, my concern is the ability of the ISO to continue to satisfy electricity demand and reserve requirements, given the system's evolving resource mix and the limitations of its fuel delivery infrastructure.

That lack of security arises, in turn, from the constraints – and uncertainties – that limit the region's supply of the necessary inputs for electric power production. As is well known, the electric power system in New England is undergoing a major transition. Over the past two decades, because of consistently low natural gas prices and New England states' incentives for renewable resources, the New England generation fleet has incorporated more and more resources with just-in-time input and intermittent energy sources. Indeed, relatively new, efficient natural gas-fired plants have displaced oil and coal for electric generation, and are providing the majority of the region's electricity. Solar-powered generation continues to grow steadily, and wind-power generation dominates the interconnection queue. In 2018, gas-fired generators provided 49 percent of New England's electric energy generation, up from just 15 percent in 2000. Coal- and oil-fired generation accounted for just one percent each of New England's electric generation in 2018, down from 18 percent and 22 percent, respectively, in 2000. Solar generation capacity has grown from just 40 MW in 2010 to 2,900 MW in 2018, and is projected to reach 6,700 MW in 2028 (all figures are nameplate, AC ratings). As of April 1, 2019, proposed solar photovoltaic and wind generation facilities comprised more than 76 percent of the capacity of proposed new resources in the ISO's interconnection queue.

Q. WHAT IS THE SIGNIFICANCE OF THESE CHANGES TO THE ISO'S ABILITY TO ENSURE THE RELIABILITY OF SYSTEM OPERATIONS?

A: Reliability standards require the ISO to prepare each day a next-day Operating Plan that ensures the power system is prepared for, and has the capabilities necessary to manage, a range of uncertainties and supply limitations. The Operating Plan must include the ability to recover from the potential "First Contingency Loss," *i.e.*, the unplanned loss of the system's largest single source of energy. As I mentioned before, historically, the generators comprising the New England fleet had ready stockpiles of fuel which they could use to run whenever the ISO needed to dispatch them to supply energy without a day-ahead commitment. Thus, if a day-ahead scheduled resource was unable to operate unexpectedly for any reason, creating an "energy gap" for the system, there were always other resources with available fuel stocks on hand to respond to dispatch instructions to provide sufficient energy to fill the gap. But nearly 25 percent of New England's total generating capacity—most of it nuclear and coal- or oil-fueled—has retired or announced its retirement since 2013. More such generation is at risk of retirement in coming years, as capacity market prices remain low, and more and more renewable generation with near-zero operating costs enters the market.

Thus, one primary risk the region now faces is the *availability* of reserves (*i.e.*, stand-by energy supplies) given the uncertainties inherent in relying on just-in-time generation resources. Specifically, though we have experienced no loss of load in New England, there is increasing risk that large portions of the region's "just-in-time," gas-fired and renewable resources will be unavailable at the same time. Accordingly, there is an increasing likelihood that, without sufficient stand-by energy supplies, there could be *insufficient energy* available to the New England power system to restore the system after a serious contingency, such as an extended loss of a large supply source, particularly during an extended period of system stress. This risk is unlikely to abate in the future, given the generation fleet's continuing, rapid shift to more and more just-in-time resources, *i.e.*, a growing number of natural gas-fired generators served by increasingly constrained interstate pipelines and rapidly expanding renewable generation capacity, as the New England states work steadily to advance their de-carbonization goals.

The other primary risk to the region is these reserves, particularly those that would provide replacement energy, may not have any meaningful incentive to provide energy, if and when called. Today, these reserves that the ISO relies upon as part of its next-day Operating Plan have little to nothing at stake, and receive no compensation for providing these critical services. This includes resources whose energy would be required to restore contingency reserves (after those reserves are activated following a large supply loss) and/or to increase energy production to meet demand when load exceeds the ISO's day-ahead forecast. While these resources are compensated for the energy they actually produce when needed, they receive no compensation for being *prepared* to provide energy (*i.e.*, provide reserves), nor are there any financial consequence if they fail to provide energy when actually needed.

As noted earlier, the RAA considers only the forecast load and reserve requirements. The current approach does not consider replacement energy. In effect, the approach *assumes* there will be enough energy available from capacity that has no day-ahead award, *and* will be capable of providing energy to fill an energy gap on the system if, for example, a unit committed day-ahead experiences an unplanned outage or a transmission failure limits a scheduled import of energy. This may not be a safe assumption as the system becomes increasingly reliant on just-in-time resources. In such an increasingly energy-limited system, it is uncertain whether there will always be other resources capable of responding with sufficient energy to permit the power system to withstand a sudden, extended (multi-hour to multi-day) loss of a large generator or other supply source, particularly during stressed system conditions.

It is the ISO's duty, as the Reliability Coordinator, Balancing Authority, and Transmission Operator for the New England region, to maintain reliable system operations, even when renewable resources experience a reduction in output or gas pipelines are constrained, or both. The evolving power system exhibits significantly different engineering and operational characteristics than the system of the past century. As the system changes, the ISO must remain capable of ensuring sufficient resources are available, and requires assurance that those resources can provide energy to satisfy the reserve requirements necessary to maintain reliable operation of the grid.

V. THE PROPOSED NEW DAY-AHEAD ANCILLARY SERVICES WILL MEET THE ISO'S NEEDS FOR CREATING RELIABLE OPERATING PLANS.

Q: DO THE PROPOSED DAY-AHEAD ANCILLARY SERVICES ADDRESS YOUR CONCERNS WITH THE ISO'S CURRENT APPROACH FOR ENSURING ITS DAILY OPERATING PLANS COMPLY WITH THE RELIABILITY STANDARDS YOU HAVE DISCUSSED?

A: Yes. The Energy Security Improvements described in the ESI White Paper align the New England wholesale energy market with the system's operational needs. Specifically, the improvements provide for the ISO to procure and compensate for new, option-based, Day-Ahead Ancillary Services that are designed to ensure the availability of energy "on demand." The new Day-Ahead Ancillary Services are modeled on the operational capabilities on which the ISO presently relies. Those capabilities are currently secured through the out-of-market processes I described earlier and are not compensated in the day-ahead timeframe. The new Day-Ahead Ancillary Services will make transparent the ISO's procurement of the reserves it requires to ensure reliable operation of the New England grid. This, in turn, will signal to Market Participants the price of reliability as the transformation of the generation fleet that I described earlier continues. The market thereby will create incentives for the resources comprising the fleet to invest in and to maintain the capabilities necessary to enable the ISO to develop, and, when required, to execute, a daily Operating Plan that meets or exceeds NERC and NPCC requirements, and thus will help improve the region's energy security.

Q: HOW DO THE PROPOSED DAY-AHEAD ANCILLARY SERVICES ALIGN WITH THE OPERATIONAL CAPABILITIES THE ISO NEEDS TO ENSURE ITS DAILY OPERATING PLANS?

A: The proposed new Day-Ahead Ancillary Services are based on the reliability standards I described above. They reflect the operational needs of the system – *i.e.*, the capabilities that the ISO relies on in developing reliable next-day Operating Plans. These capabilities fall into three broad reserve categories, corresponding to the three broad operational categories I described earlier.

1. Energy Imbalance Reserve ("EIR") is energy from resources the ISO *may* require to balance load and supply when the total day-ahead cleared energy supply is less than the ISO's forecast real-time energy demand (load), in a given hour, during the next Operating Day. This reserve requirement is in addition to, and distinct from, reserve requirements to handle supply loss contingencies, which I describe below. Currently, the ISO covers the load-balance gap by dispatching resources above their Day-Ahead Energy Market schedules, or the supplemental, *i.e.* out-of-market, commitment of resources in the RAA process. The Energy Security Improvements incorporate the ISO's load forecast for the next day into the Day-Ahead Market. Accordingly, the ISO will procure EIR when that forecast exceeds total physical supply cleared in the Day-Ahead Market.
2. Generation Contingency Reserve ("GCR") comprises three different Operating Reserve-type ancillary services: Day-Ahead Ten-Minute Spinning Reserve, Day-Ahead Total Ten-Minute Reserve, and Day-Ahead Thirty-Minute Operating Reserve, each consistent with the capabilities required under NERC BAL-002-3, Requirements

R.1 and R.2; NPCC Directory #5; and the ISO's OP-8.

3. Replacement Energy Reserve ("RER") comprises two different contingency reserve restoration-type (*i.e. replacement* energy-type) ancillary services: Day-Ahead Ninety-Minute Reserve and Day-Ahead Four-Hour Reserve, each consistent with the capabilities needed for restoration of contingency reserves (GCR) within the prescribed timeframes. RER will also be used to account for load forecast error.

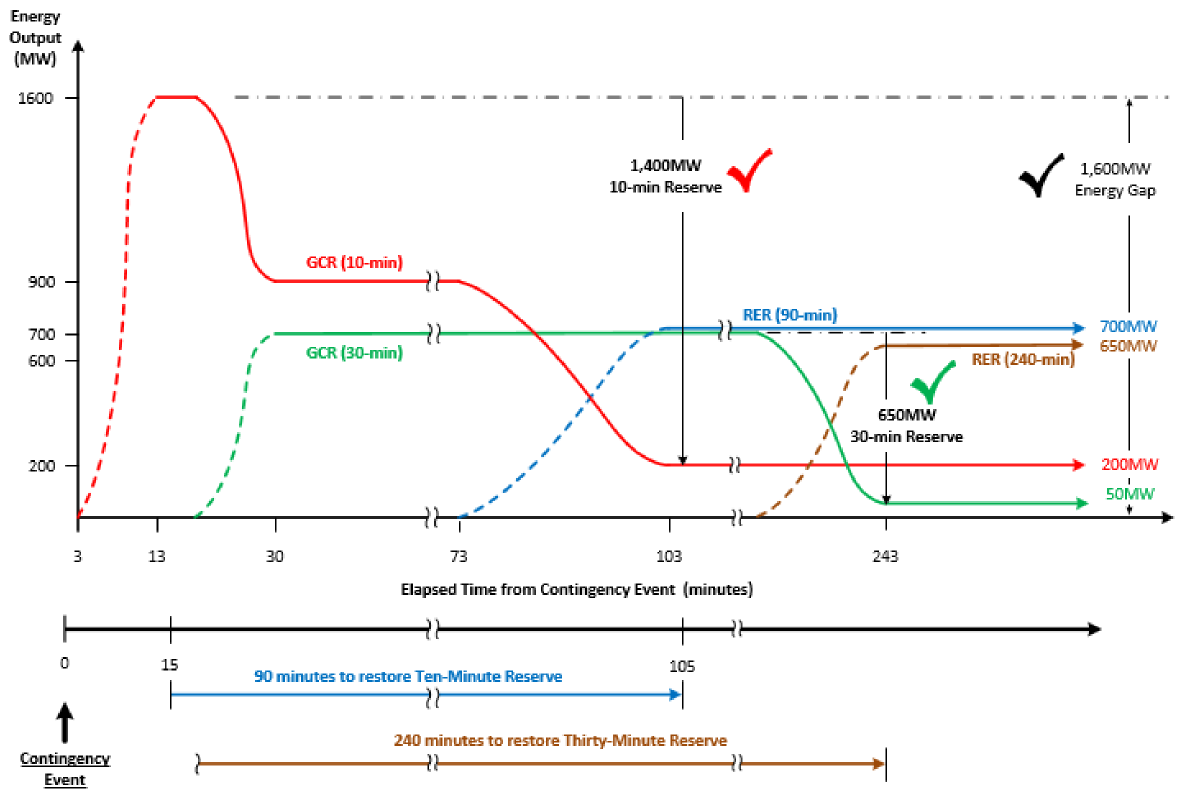
Q: HOW ARE THE GCR AND RER DAY-AHEAD ANCILLARY SERVICE REQUIREMENTS DETERMINED?

A: The ISO will formulate the day-ahead requirements for the three GCR ancillary services in the same manner as is done currently—based on the anticipated first and second largest contingencies in each hour of the following day, and taking into account the historical non-performance factor for reserves. Similarly, the ISO will formulate the day-ahead requirements for the two RER ancillary services based on the amounts needed to restore Operating Reserves, in the context of GCR, within the specified timeframes.

Q: CAN YOU PROVIDE AN EXAMPLE OF HOW THE ISO WILL DETERMINE THE AMOUNTS TO BE PROCURED FOR GCR AND RER?

A: Yes, the amount of the GCR and RER to be procured day-ahead can best be illustrated by using the same example and depictions I described earlier in my testimony. For convenience, Figure 2 is presented again here:

Figure 2



The specific amounts are as follows:

- The Day-Ahead Total Ten-Minute Reserve Demand Quantity (or requirement) is equal to 100% of the First Contingency Loss depicted by the red line in the diagram. In the example, the amount is set by Resource A, which is 1600 MW.
- The Day-Ahead Total Thirty-Minute Operating Reserve Demand Quantity (the analog to the simplified 'Total Reserve requirement' in the example) is equal to 100% of the First Contingency Loss and 50% of the Second Contingency Loss. In the example, the amount is set by the 1600 MW from Resource A and 50% of Resource B, which is 700 MW, for a total of 2300 MW.
  - The total requirement reflects the one-way product substitutability between the ten-minute reserve product and the thirty-minute reserve product. Specifically, ten-minute reserve may be used as a substitute for thirty-minute operating reserve. However, thirty-minute reserve cannot be used as a substitute for ten-minute reserve.
  - Consequently, the Day-Ahead Total Thirty-Minute Operating Reserve Demand Quantity may be satisfied, in part, by resources providing the Day-Ahead Thirty-Minute Operating Reserve, which, in the example, is

700 MW as depicted by the green line in the diagram.

- The Day-Ahead Total Ninety-Minute Reserve Demand Quantity is equal to 100% of the First Contingency Loss and 100% of the Second Contingency Loss (3000 MW total in the example).
  - Again, the total requirement reflects the one-way product substitutability between the ten-minute reserve product, the thirty-minute reserve product, and now the ninety-minute reserve product. Ten-minute or thirty-minute reserve may be used as a substitute for ninety-minute reserve. However ninety-minute reserve cannot be used as a substitute for either ten-minute or thirty-minute reserve.
  - Consequently, the Day-Ahead Total Ninety-Minute Reserve Demand Quantity may be satisfied, in part, by resources providing the Day-Ahead Ninety-Minute Reserve, which is 700 MW in the example, as depicted by the blue line in the diagram.
- The Day-Ahead Four-Hour Reserve Demand Quantity is equal to 100% of the First Contingency Loss and 100% of the Second Contingency Loss, plus 50% of the third contingency loss (3650 MW total in the example).
  - Here again, the total requirement reflects the one-way product substitutability between the ten-minute reserve product, the thirty-minute reserve product, the ninety-minute reserve product, and now the four-hour reserve product.
  - Consequently, the Day-Ahead Total Four-Hour Reserve Demand Quantity may be satisfied, in part, by resources providing Day-Ahead Four-Hour Reserve, which is 650 MW in the example, as depicted by the brown line in the diagram.

Q: DOES THIS CONCLUDE YOUR TESTIMONY?

A: Yes.

I declare under penalty of perjury that the foregoing is true and correct.

Executed on April 13, 2020

Peter Brandien

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Peter T. Brandien

Attachment B

Affidavit of Dr. White

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

	)	
ISO New England Inc.	)	Docket No. EL18-182-_____
	)	

AFFIDAVIT OF MATTHEW WHITE
ON BEHALF OF
ISO NEW ENGLAND INC.

My name is Matthew White. I am the Chief Economist for ISO New England Inc. ("ISO"). My business address is One Sullivan Road, Holyoke, Massachusetts 01040.

My primary responsibilities at the ISO include the design and development of the ISO's suite of auction-based electricity markets. Prior to joining the ISO, I held faculty appointments at the University of Pennsylvania's Wharton School of Finance and Commerce (2002-2009) and Stanford University's Graduate School of Business (1995-2001). At these institutions I conducted research on electricity demand, pricing, and market design, and taught graduate-level courses in economics and decision analysis. My public service includes appointments as a senior staff economist at the Federal Energy Regulatory Commission, Office of Energy Policy and Innovation (2009-2010) and the Federal Trade Commission, Bureau of Economics (2001-2002). My research studies have been published in peer-reviewed economics journals, and I have served as a referee and evaluator for the National Science Foundation and over twenty-five journals spanning economics, engineering, and political science. I received a M.S. in Statistics and a Ph.D. in Economics from the University of California, Berkeley.

I am providing this affidavit in support of the changes to the ISO New England Inc. Transmission, Markets and Services Tariff filed here to implement the "Energy Security Improvements," as fully described in the accompanying transmittal letter and white paper titled "Energy Security Improvements: Creating Energy Options for New England." I am the principal author of that white paper, participated in the drafting of the transmittal letter, and led the ISO's market design effort for this project.

I declare that the information included in the white paper and transmittal letter is true and correct to the best of my knowledge and belief.

Matthew White, Chief Economist, ISO New England Inc.

Executed on April 15, 2020.

Energy Security Improvements: Creating Energy Options for New England

April 15, 2020

This paper describes in detail the changes to the ISO New England Transmission, Markets and Services Tariff ("Tariff") being filed on April 15, 2020 to address potential energy security problems in New England. These changes comply with the Federal Energy Regulatory Commission's 2018 directive that ISO New England submit "Tariff revisions reflecting improvements to its market design to better address regional fuel security concerns."[1] This paper explains the underlying causes of these problems and how the improvements to the market design will address them.

[1] Order Denying Waiver Request, Instituting Section 206 Proceeding, and Extending Deadlines, 164 FERC ¶ 61,003 at P 2 (2018) ("July 2, 2018 Order").

Energy Security Improvements: Creating Energy Options for New England

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1. Introduction and Summary

The electric power system in New England is undergoing a major transition. The owners of traditional power plants – nuclear, coal, and oil-fired – are permanently shuttering many of these stations due to economic and environmental pressures.[2] The majority of the region's electricity, both currently and for the foreseeable future, is likely to come from newer, more efficient natural-gas-fired generation and an array of renewable energy technologies, such as solar and wind.

This evolution comports well with the New England states' goals for a cleaner, greener regional power grid, yet it also presents new challenges. Both renewable and natural gas-based generation technologies rely on the "just-in-time" delivery of their energy sources. Solar- and wind-based power inherently vary with the weather. Less obviously, and of greater concern presently, is the just-in-time delivery of natural gas across interstate pipelines to the region's generating stations. During cold winter conditions, these pipelines rapidly reach capacity and are unable to fuel many of New England's power plants.[3]

Given the power system's increasing reliance on these just-in-time resources and the region's constrained fuel delivery infrastructure, ISO New England Inc. (ISO) is concerned that there may be insufficient energy available to the New England power system to satisfy electricity demand during cold winter conditions. While there has been no loss of load attributable to insufficient energy supplies to date, the ISO is concerned that industry trends will increase this risk over time unless proactive solutions are developed.[4]

In practice, reducing the risks that arise in a power system increasingly reliant on just-in-time energy sources requires additional sources of energy supply (or reductions in demand) when gas pipelines are most constrained, when renewable resources experience adverse weather, or both. Additional energy supply (specifically, fuel) arrangements can enable existing fossil-fired generating stations to perform reliably during such conditions. Examples include arrangements by natural gas-fired generators to procure and maintain liquefied natural gas (LNG) inventories at existing LNG facilities in the Northeast (for use when the interstate pipelines are constrained during winter), and making advance arrangements for fuel oil supplies to be promptly replenished during winter at the region's dual-fuel (oil and gas) and oil-based power plants. Over the longer term, a broader array of capital investments may ultimately produce cost-effective alternatives. These may include greater price-sensitive demand participation in the wholesale markets, local "satellite" LNG storage facilities near

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[2] *See* ISO New England Status of Non-Price Retirement Requests, Retirement De-list Bids, and Substitution Auction Demand Bids, available at https://www.iso-ne.com/static-assets/documents/2016/08/retirement_tracker_external.xlsx (showing all pending and retired capacity resources from 2013 through 2024).

[3] *See* Energy Security Improvements: Market Solutions for New England, Speaker materials of Matt White and Chris Parent, ISO New England, at the ISO New England Fuel Security Noticed Meeting, FERC Docket No. EL18-182-000 (filed July 15, 2019), at Slides 9-11.

[4] *See, e.g.*, *Winter Energy Security Improvements* memorandum from the ISO to the NEPOOL Markets Committee, dated September 6, 2018, available at https://www.iso-ne.com/static-assets/documents/2018/09/a9_iso_memo_winter_energy_security_improvements.pdf, at pages 2-3.

generation stations, and innovative electricity storage technologies (like grid-scale batteries) that can smooth out the intermittency of renewable energy resources.

Unfortunately, the existing energy market structures do not properly incent such investments. The competitive power sector's willingness to undertake any of these reliability-enhancing-but-costly endeavors depends on their expected return on the investment. As discussed in the next section, however, the very act of making those costly investments can dramatically reduce (or eliminate) the expected return on that investment. As a result, investments that would both improve reliability and be cost-effective from a societal perspective are not cost-effective for the competitive suppliers making these decisions.

Bearing this out, the region's competitive power sector has made little progress with these reliability-enhancing investments. In recent winters, few natural-gas fired generators have made advance arrangements for LNG inventories in New England; and by some measures, the generation fleet's fuel oil inventories for winter power generation are declining over time, due to both economic factors and emissions restrictions.[5]

Addressing these very issues, the Federal Energy Regulatory Commission (Commission) in 2018 directed the ISO to submit "Tariff revisions reflecting improvements to its market design to better address regional fuel security concerns."[6] That directive arose amidst a contentious regulatory process involving shorter-term, non-market actions to bolster the region's fuel supplies by delaying the retirement of the large Mystic Generating Station near Boston, Massachusetts. Expressing a clear preference for a different path forward, the Commission reaffirmed its "support for market solutions as the most efficient means to provide reliable electric service to New England consumers at just and reasonable rates," and expectations for the ISO "to develop longer-term market solutions."[7]

To that end, after addressing the problems and causes of these energy security concerns, this paper describes in detail the market-based solutions (referred to herein as the "Energy Security Improvements") that the ISO has developed and vetted with regional stakeholders. In short, while the power system's growing reliance on technologies with just-in-time energy sources poses new challenges, we believe these challenges have sensible solutions. Further, we readily agree with the Commission's affirmation that these challenges are most appropriately addressed through market mechanisms. As the technologies comprising New England's power grid continue to rapidly evolve, harnessing the forces of competition will provide the most cost-effective long-term solutions.

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[5] *See, e.g.*, *Responses to Questions Relative to Energy Security Proposal* memorandum from the ISO to Joint Requestors, dated March 21, 2019 (revised), available at https://www.iso-ne.com/static-assets/documents/2019/01/a7_iso_memo_containing_responses_to_joint_requestors_questions_on_energy_security_proposal.pdf, at pages 2-5.

[6] July 2, 2018 Order at P 2.

[7] July 2, 2018 Order at PP 53, 54.

1.1 Problems and Causes

To facilitate analysis of the region's energy security concerns and potential solutions, this paper begins with a deeper examination of the underlying problems and their root causes. Our focus is whether the ISO-administered wholesale electricity markets – which were not originally designed for the challenges that just-in-time generation technologies have wrought – provide adequate financial incentives for resource owners to make additional investments in energy supply arrangements that would be cost-effective and benefit the power system at times of heightened risk.

Our central conclusion is that, in many situations, the answer is no. Even when such energy supply arrangements would be cost-effective from society's standpoint as a means to reduce reliability risks, the ISO's current suite of market products do not provide sufficient financial incentives for market participants to undertake them. The root cause is logical enough. Making these discrete investments entails up-front costs to the generator. But if those investments meaningfully reduce the risk of electricity supply shortages (and therefore the risk of high prices), then they will also reduce the energy market price the generator receives. The value that society places on the generator's energy supply (*e.g.*, fuel) arrangements is based on the high price society *avoids* as a result of the investment. However, the value the generator places on the same arrangement is based on the lower price that it *receives* in the energy market with the investment. This divergence between the social and private benefit of the investment represents a significant *misaligned incentives* problem.

In effect, given how New England's power system has evolved, generation owners face a "no-win" situation: If a generator *does not* make, for example, a costly additional fuel supply arrangement, then when the region's gas pipelines are tightly constrained and renewables' output is low, high real-time wholesale energy market prices will prevail. These high prices cost consumers dearly, but do not immediately benefit the generator if it lacks fuel to operate (because it did not make the necessary fuel supply arrangements). Those high market price signals normally motivate widespread investment to profit in such circumstances. And yet, if the generator *does* invest in more robust fuel supply arrangements – at least, to a level that meaningfully reduces the system's energy supply risk – then the investment may obviate the market's high energy price, undermining the generator's expected return on the investment. Given these misaligned incentives, and that nearly any investment in additional energy supply arrangements tends to entail significant costs up-front, it is no surprise that few generation owners perceive adequate incentives to undertake them.

To explore this problem in detail, this paper provides a series of numerical examples. These are intended to help make the nature of the problem, and the conditions on which is rests, readily apparent. The bottom line is that investing in more robust energy supply (*e.g.,* fuel) arrangements may often be beneficial and cost-effective for the system, but not financially viable for individual generators in the ISO's present energy market construct.

Deconstructing this problem in detail, as we do in this paper, has a useful summary implication: the suite of products in the ISO-administered energy markets is incomplete. Their current form and associated ancillary service products were designed more than fifteen years ago, well before just-in-time energy powered the majority of New England's generation. In that earlier era, capacity supply was a constraining reliability concern. Specifically, as long as the system had sufficient operable capacity committed each day, another increment of energy demand could be satisfied by dispatching up the next generator. In today's environment, however, we do not face a capacity shortfall problem (indeed, the system is awash in capacity). We, instead, face an *energy security* problem due to the constraints and uncertainties that limit the region's energy supply for power production.

► **Essential Reliability Services for Managing Energy Uncertainty.** In New England, most resources that clear in the day-ahead energy market successfully operate during the hours for which they receive a day-ahead energy schedule. That has been true since the competitive markets' inception more than twenty years ago, and remains true today.

Consider, however, the situation when a large resource clears day-ahead, but is subsequently unable to operate for an extended (multi-hour or multi-day) duration. This creates an unanticipated 'energy gap' in the day's operating plan. The replacement energy to fill that gap must come from other resources operating above their day-ahead awards (or resources that did not receive a day-ahead award).

With the region's growing dependence on just-in-time energy sources and its constrained fuel delivery infrastructure, however, those replacement resources – which did not expect to run – may not be able to operate unless they invested in robust energy (*e.g.,* fuel) supply arrangements in advance of the operating day. Yet in today's market construct, it is generally unprofitable to incur the costs of procuring fuel to cover days for which a resource did not expect to operate – or to be paid.

In practice, the ISO relies upon much of the generation fleet's capabilities, above and beyond their day-ahead energy awards, for the essential reliability services necessary to fill such 'energy gaps.' In concrete terms, these capabilities fall in three operational categories:

- resources capable of providing energy to cover the gap when the total energy supply cleared in the day-ahead market from physical resources (*e.g.,* generation and net imports into New England) is insufficient to serve the forecast electricity demand for the next operating day;

- resources capable of providing fast-start / fast-ramping contingency response, which enable the system to promptly close the gap between energy supply and demand following an unanticipated supply loss (consistent with the timeframes established in applicable reliability standards); and

- resources capable of providing replacement energy, for the balance of the operating day, when and as needed to restore the contingency reserve resources to reserve status and to serve an unanticipated increase in energy demand.

As discussed in detail in later sections, we distinguish these three categories insofar as they involve conceptually distinct services and capabilities. In particular, they require different resource capabilities in order to cost-effectively address potential energy gaps that arise on, and persist for, different timeframes.

At present, the ISO does not procure or compensate for these types of ancillary service capabilities on a day-ahead timeframe. That may have been reasonable in the past, when generators without day-ahead energy schedules characteristically had large, ready stockpiles with which to fuel an unexpected, extended run whenever an energy gap arose. But, as noted previously, those generators are retiring, and many that remain are at risk of future retirement.

Thus, it is important to improve today's energy market construct so that the future resource mix will invest in energy supply arrangements and technologies that ensure these essential reliability services – and the requisite resource capabilities – remain available to the power system each operating day.

1.2 Solutions

The second portion of this paper introduces market design improvements to address these problems. The overall design is based on a familiar set of energy and ancillary service concepts. Broadly, these changes expand the existing suite of energy and ancillary service products in the ISO-administered markets, in order to address – reliably and cost-effectively – the uncertainties and supply limitations inherent to a power system becoming more and more reliant on just-in-time energy technologies.

Building upon the region's competitive wholesale electricity structure, the ISO intends to create several new, voluntary ancillary services in the day-ahead market that provide, and compensate for, the flexibility of energy 'on demand' to manage uncertainties each operating day. These services will help signal, through transparent market prices, the costs of operating a reliable power system as the profile of resources comprising the New England fleet continues to evolve. And they will help ensure that the system is prepared for, and has the capabilities to manage, a range of uncertainties in a power system increasingly reliant on just-in-time technologies.

► **New Day-Ahead Ancillary Services as Call Options on Energy.** The changes described herein will formalize the foregoing three categories of operational needs (listed in Section 1.1 above) into specific ancillary service capabilities and allow resources to compete to provide those capabilities in the ISO's day-ahead markets. Offers to provide those ancillary services will be voluntary, and awards compensated at uniform, transparent, product-specific market prices. At a high level, a day-ahead seller of those ancillary services is providing the ISO with an on-demand "call" on its energy during the operating day, with different lead times applicable to the different ancillary service products.

To procure these services cost-effectively, the award of these ancillary services will be co-optimized (that is, simultaneously cleared) with all participants' energy supply and demand awards in the day-ahead market. That co-optimization process ensures, by design, that the clearing prices for energy and each ancillary service incorporate the (marginal) suppliers' opportunity costs of not receiving an award for a different day-ahead product. It also means that the day-ahead prices for energy will commonly incorporate the clearing prices for the ancillary services as well. As a result of procuring multiple new products in the day-ahead market, the day-ahead market's total energy compensation to suppliers will also be higher than under the current rules.

The new co-optimized market design also adds a new component to the day-ahead market's energy compensation to supply resources – in addition to new ancillary service revenue. This new component – the 'forecast energy requirement' – will provide greater revenue to resources with day-ahead obligations to supply energy and that contribute to a reliable next-day operating plan for the power system, strengthening their incentives to invest in additional energy supply arrangements.

For the three new ancillary services, a central design feature is their settlement. Consistent with their value as a call option on energy during the operating day, a day-ahead ancillary obligation will be settled as a proper call option on real-time energy. That is a familiar, standard multi-settlement rule used in a wide variety of commodity markets to manage uncertainty. Moreover, it functions well in concert with the existing day-ahead energy market's two-settlement design. The second (real-time) settlement is slightly different for day-ahead energy and for ancillary service positions, however, reflecting that the former is a forward sale (or purchase) of real-time energy and the latter is call option on real-time energy.

Importantly, an option settlement design creates strong new incentives for sellers of these ancillary services to ensure they have the physical ability (including fuel) to cover their obligations the next day. This is because a resource that commits to providing an ancillary service will face a steep financial consequence if the real-time energy price is high and the resource does not perform. Using a series of numerical examples, this paper will explain how this approach provides stronger incentives than the existing market design for resources to incur the costs of additional energy supply arrangements. At the same time, resource owners will receive new day-ahead compensation to cover their costs of additional energy supply arrangements, even if it turns out that their resources are not needed for the system to operate reliably on the next day.

These product design and settlement features fundamentally change the incentives that suppliers face. From a commercial standpoint, it will become profitable for the resources that the ISO relies on for these ancillary services to incur the costs of maintaining more reliable energy supply arrangements, when such arrangements are cost-effective from the standpoint of the system overall – helping ensure they *could* perform if needed to fill an energy gap, even on days they did not expect to operate.

1.3 Benefits

As noted above, in 2018 the Commission directed the ISO to develop and file longer-term market solutions "reflecting improvements to its market design to better address regional fuel security concerns."[8] Furthermore, the Commission emphasized its "support for market solutions as the most efficient means to provide reliable electric service to New England consumers at just and reasonable rates."[9] Consistent with these directives, the significant benefits of the Energy Security Improvements fall into three broad categories. First and foremost, these improvements achieve the

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[8] July 2, 2018 Order at P 2.

[9] July 2, 2018 Order at P 53.

Commission's requirement to improve fuel security for the region. Second, they do so in a fully market-based manner. Third, the Energy Security Improvements have other important benefits beyond energy security. We summarize each of these benefits here.

1.3.1 The Energy Security Improvements Will Improve Fuel Security in New England, as Directed by the Commission, by Solving the Misaligned Incentives Problem

The ISO is confident that the Energy Security Improvements will enhance fuel security in New England, and will promote more robust energy supply arrangements broadly, in a fuel- and technology-neutral manner. They will do so in three distinct ways:

First, the Energy Security Improvements will procure new ancillary services in the day-ahead market that will more completely reflect the daily operational needs of the system. The new design will formalize, through the market, the option to call upon 3,000 to 5,000 MW of reserves each day to help ensure reliable operations. These are capabilities that the ISO currently relies on, but that are not adequately compensated for such service under the current rules. Recognizing these capabilities in the Day-Ahead Energy Market will ensure that the system is prepared in advance to respond when the region faces the types of real-time stressed system conditions that, in the past, have created concerns over fuel security.

Second, the Energy Security Improvements will provide more accurate and stronger price signals to suppliers during tightening (limited supply) conditions, including conditions arising from the region's fuel infrastructure limitations.[10] These day-ahead price signals will provide an early warning that market conditions are tightening when there is not yet an actual scarcity condition (that is, a real-time shortage of energy or reserves). That will provide suppliers with commensurately increasing incentives to invest in additional energy supply arrangements so they are prepared when challenging operating conditions do arise, and it appropriately compensates those suppliers for their efficiency and flexibility.

Third, the Energy Security Improvement create new financial consequences for resources that offer to provide these essential capabilities but then do not perform during tight market conditions. Resources selling these new ancillary services will be financially responsible for not supplying energy in real-time, with the market design specifying that the cost of not supplying energy be based on the real-time energy price (which can exceed $3,800 per MWh during periods of scarcity).[11]

Together, these three inter-woven improvements will provide additional incentives, and the compensation (and potential consequences) necessary, for resources to bolster their fuel and

[10] In this regard, Energy Security Improvements will operate in tandem with other recent enhancements that enable the markets and participants to better respond to changes in system conditions, including a mechanism to better enable fuel-constrained resources to reflect their (opportunity) costs in energy market offers, and improvements to the forward-looking (21-day) information provided to market participants about expected energy supply conditions.

[11] It is worth noting that the Energy Security Improvements will not operate in a vacuum; rather, the combination of reserve shortage pricing in the energy market and the fully phased-in "Pay For Performance" penalty rate in the capacity market will create an effective energy price that can exceed $9,000 per MWh during real-time scarcity conditions.

energy-source arrangements. In this manner, the Energy Security Improvements will directly address the misaligned incentives problem mentioned previously, by meaningfully strengthening incentives for effective participant-driven supply-chain management and reliable fuel (or other input energy) supply arrangements by resource owners. Importantly, the ISO is not aware of another market design that could achieve the same outcome.

The likely efficacy of the Energy Security Improvements is evident in the results of the Impact Assessment work performed by the Analysis Group, Inc. Overall, that detailed study finds it profitable for many resources to maintain greater fuel inventories under the Energy Security Improvements design, relative to the current market rules. For example, in Section IV.A.1.c of the Impact Assessment, the Analysis Group finds that the new revenue streams introduced by the Energy Security Improvements are sufficient to incent significantly greater oil inventories (and replenishments thereof) across a range of resource types and market conditions.[12] Notably, Tables 11 through 13 of the report show that when resources increase their oil inventory during the winter in response to the new revenue streams, they will – in nearly all scenarios studied – earn significant returns from such investments.[13]

Similarly, Section IV.A.1.d of the assessment shows that the Energy Security Improvements will tend to increase incentives for natural gas resources to consider entering into winter peaking gas contracts. While the assessment does not definitively determine the extent to which the changes would incent generators to sign such contracts, it finds that the returns associated with such contracts are greater with the Energy Security Improvements than under the current market rules during stressed winter cases, and therefore concludes that the introduction of these improvements increases this likelihood relative to current market rules.[14]

More broadly, the full spectrum of the Analysis Group's results supporting the efficacy of the Energy Security Improvements is exactly what one would expect from an economically sound market design that better addresses the region's fuel security concerns.

1.3.2 The Energy Security Improvements are Fully Market-Based, with Many Attendant Benefits

The Energy Security Improvements will improve the bulk power system's energy security by using a sensible market approach that signals, through transparent, day-ahead prices, the costs of satisfying the region's electricity needs at all times, including during periods of severely stressed system conditions. When *fuel* scarcity is properly priced – that is, through its impact on *energy and reserves* scarcity – the wholesale electricity markets will appropriately compensate all resources that contribute to the system's reliability. Consistent with sound market design, they will also incent

[12] *See Energy Security Improvements Impact Assessment* by Analysis Group, Inc., provided as Attachment C to the Energy Security Improvements filing ("Impact Assessment"), dated April 2020, at Section IV.A.1.c.

[13] *See* Impact Assessment at Section IV.A.1.c, Tables 11-13.

[14] *See* Impact Assessment at Section IV.A.1.d and Table 15.

cost-effective investments by resources that can provide the greatest reliability benefits to consumers. The many benefits of this market-based approach include:

► **Fuel and Technology Neutrality.** Centrally, the Energy Security Improvements are focused on promoting reliable electric energy and ancillary services *output* – and are, by design, fuel and technology neutral. The design rewards resources, of any technology or fuel type, that acquire a day-ahead commitment to supply energy or ancillary services and thereby contribute to the system's daily reliability requirements – including renewable resources, traditional and emerging storage technologies, and traditional fossil-fueled generators. In short, these improvements will strengthen the financial incentives for generation owners to undertake more robust energy supply arrangements, when cost-effective, while not proscribing what form those supply arrangements may take.

► **Cost Effectiveness.** Providing incentives through the market for electric energy and reserves (again, paying for energy outputs, not fuel inputs) will help to ensure that the Energy Security Improvements will address the region's fuel security concerns in a cost-effective manner. Owners of resources of any type or technology will have strong incentives to firm-up their fuel or other energy supply sources, through whatever means they find most cost-effective, to support their day-ahead market obligations. By contrast, non-market mechanisms (such as direct subsidies to selected generators to procure additional fuel) benefit only those selected resource owners, providing no incentives to other resources – or to potential new technologies, such as storage – that may help comprise cost-effective, long-term solutions.

► **Transparency.** Because these new incentives will be provided through a market-based mechanism, they are signaled through market prices visible to all. In this way, the Energy Security Improvements extend a fundamental benefit of markets – their price transparency. The visibility of the market's strengthened resource incentives will encourage more efficient investments in energy supply arrangements than the current markets – investments that seek to reduce reliability risks in New England's increasingly energy-constrained power system.

► **Consistency with Existing Market Design.** The Energy Security Improvements logically extend the concepts that underlie the region's s longstanding energy markets. The new products and services will work smoothly with the existing day-ahead and real-time markets, filling the gap in the current markets' product suite by providing new compensation for resource capabilities not presently remunerated in the day-ahead market.

► **Fairness and Innovation.** The Energy Security Improvements will compensate all technologies capable of providing energy or any of the new ancillary services, creating a level playing field for market participants. And because no capable technology is excluded, this design should foster innovation, as participants explore the best technologies or other means to capitalize on the new products.

► **Risk-Responsiveness.** Using a market-based approach to address these issues will ensure that the costs of improving the region's energy security are related to the risks. If the region's energy security risks are not realized in future years – perhaps because they are meaningfully reduced through different policies outside the ISO-administered markets (say, through much greater renewable energy production and storage in future years) – then providing these new products and services would have lower costs for sellers, and procuring these products and services would have lower costs for consumers. That 'risk-responsive' aspect of the overall design prevents locking consumers into new multi-year obligations that might prove both expensive and unnecessary, as New England's power system continues to evolve.

1.3.3 The Energy Security Improvements Have Benefits Beyond Energy Security

The Energy Security Improvements will also have several benefits not directly related to energy security. While those "co-benefits" are not the immediate objective of this filing, they will enhance both the benefits of New England's competitive wholesale electricity markets and the ISO's ability to manage the region's rapidly evolving power system reliably.

For one, the Energy Security Improvements to the market design have important price formation benefits. The ISO presently relies upon a variety of unpriced and "out-of-market" actions in the energy market to ensure the system can satisfy certain reliability standards – all because the existing market design is incomplete. That is, the current design lacks prices for specific day-ahead ancillary services needed to ensure that the system has a next-day operating plan that satisfies the applicable reliability standards and requirements (as discussed in more detail in Section 2.6.1 below). In contrast, the Energy Security Improvements filed here will use transparent markets – with well-defined market products, transparent market-clearing prices, and competitively-determined awards – to ensure that the system has a next-day operating plan that satisfies these standards and requirements.

This is a significant benefit, as it helps to ensure that competitive market prices appropriately convey the costs of operating a reliable power system. That, in essence, is the central goal of price formation improvements generally. And in this way, the Energy Security Improvements advance the broader Commission-approved corporate mission of the ISO to "provide an opportunity for a participant to receive compensation through the market for a service it provides in a manner consistent with proper standards of reliability."[15]

The Energy Security Improvements are also tightly coupled to existing reliability standards, and do not purport to create a new standard for fuel security. The new design will ensure that existing reliability standards – as set forth in current North American Electric Reliability Corporation ("NERC") and Northeast Power Coordinating Council ("NPCC") standards, as well in the ISO's Operating Procedures – are met, in a cost-effective manner. These standards are described in detail in the Testimony of Peter T. Brandien, Vice President of System Operations and Markets Administration, provided as an attachment to the Energy Security Improvements filing.[16] In that testimony, Mr. Brandien explains how the Energy Security Improvements align with the operational capabilities

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[15] Tariff Section I.3(b).

[16] *See* Testimony of Peter Brandien, Vice President of System Operations and Market Administration of the ISO, provided as Attachment A to the Energy Security Improvements filing ("Brandien Testimony"), at pp. 6-17.

needed to ensure that the ISO's daily operating plans comply with those existing reliability standards.[17]

Finally, the Energy Security Improvements will also help the ISO to manage the rapid growth of renewable resources participating in the New England markets.[18] As mentioned earlier, the New England region is becoming increasingly dependent on intermittent and renewable resources with "just-in-time" delivery of their input energy sources (sun and wind). Energy production from such resources is dependent on the weather, and is therefore uncertain day-to-day. The Energy Security Improvements will help the system to manage the uncertainty over the next-day energy production of these resources. Specifically, the new ancillary service products being introduced with this filing are well-suited for addressing operational uncertainties that affect generators' input energy sources, whether they arise from adverse weather or constrained fuel supply conditions. Furthermore, the new market design improvements will fundamentally reward resource flexibility that helps the ISO to manage, and prepare for, energy supply uncertainties during the operating day.

*   *   *

In sum, the Energy Security Improvements will strengthen financial incentives for generators to undertake more robust supply arrangements, when cost-effective, while not proscribing what form those supply arrangements may take; reward resource flexibility that helps to manage, and prepare for, energy supply uncertainties during the operating day, given the increasingly just-in-time nature of the power system; and enable New England's competitive markets to better signal, through transparent prices, the costs of operating a reliable power system as it continues to evolve.

The balance of this paper provides further perspective on problems and causes, the specific goals of the new ancillary services, and explains in detail how they will work. In Section 2, we examine the problems and their root causes in detail, and illustrate the challenges they present with a series of numerical examples. In Section 3, we summarize the design objectives and principles that guide the ISO's development of market improvements to address these challenges. In Section 4, we delve into the new energy option design for the day-ahead markets and its settlement. In Section 5, we show how this energy option design solves the misaligned incentives problem and directly incents greater expenditure on cost-effective energy supply arrangements, using a series of numerical examples. In Sections 6 through 9, we detail each specific new ancillary service product and their impact on day-ahead energy market prices, covering specific rationales, pricing, clearing, relations to reliability standards, and providing additional numerical examples to illustrate market outcomes. Section 10 concludes.

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[17] *See* Brandien Testimony at pp. 26-30.

[18] *See* Energy Security Improvements: Market Solutions for New England, Speaker materials of Matt White and Chris Parent, ISO New England, at the ISO New England Fuel Security Noticed Meeting, FERC Docket No. EL18-182-000 (filed July 15, 2019), at Slide 6.

2. Problems and Causes

In this section, we provide a deeper diagnosis of the problems and causes underlying the ISO's energy security concerns. To lend clarity to these concerns, we identify several specific adverse consequences that arise under the current market design – consequences that may become more significant in the future, as the number of resources with just-in-time energy sources grows. The analysis of these consequences, and their root causes, has guided the development of the market-based solutions presented in Sections 4-7 of this paper.

2.1 Focusing Deeper: Three Specific Problems

Energy security is a broad term subject to a myriad of competing interpretations. To provide focus, we constructively frame the power system's emerging energy supply risks in terms of three specific problems, enumerated below. These have interrelated market and operational components, and adversely affect both the efficiency and reliability of New England's power system.

Problem 1: **Misaligned Incentives.** Market participants whose resources face production uncertainty may have inefficiently low incentives to invest in additional energy supply arrangements, even though such arrangements would be cost-effective from society's standpoint as a means to reduce reliability risks.

Problem 2: **Operational Uncertainties.** There may be insufficient energy available to the power system to withstand an unexpected, extended (multi-hour to multi-day) large generation or supply loss, particularly during cold weather conditions.

Problem 3: **Insufficient Day-Ahead Scheduling.** New England's current energy-only day-ahead market commonly schedules (that is, clears) insufficient energy to meet the ISO's forecast load for the next operating day.

The first of these problems is one of misaligned incentives. Investing in more robust energy supply (*e.g.,* fuel) arrangements may not be financially viable for individual generators in today's market construct, yet can be beneficial and cost-effective for the system. This has both efficiency and potential reliability consequences. We address this problem in detail first.

The second of these problems relates to operational 'energy gap' situations. With the region's growing dependence on just-in-time energy sources and its constrained fuel delivery infrastructure, generating resources that do not expect to run the next day (*i.e.,* that do not receive an award in the day-ahead market) may not have sufficient energy to operate – unless they made costly fuel supply arrangements in advance. These concerns are heightened by the fact that the ISO currently relies upon much of the generation fleet's capabilities, above and beyond their day-ahead energy awards, to fill any energy gaps that arise during the operating day.

The third of these problems is the potential imbalance between the day-ahead market's outcomes and the system's requirements for a reliable next-day operating plan. The ISO's markets presently enable buyers to procure energy in the day-ahead market, yet also provides them with the "free" option to wait and reveal their demand only in real-time. That option is not costless to the system, however. When market participants procure less energy in the day-ahead market than the ISO's forecast energy demand for the next operating day, the system must cover that gap by scheduling additional resources (or additional output beyond day-ahead cleared resources' energy schedules) after the day-ahead market. That out-of-market reliability process ensures that the system can cover the forecast energy demand, but does not transparently signal the costs of those post-market actions. Nor does it provide the same compensation and incentives for generators to arrange fuel that the day-ahead market provides, contributing to the region's fuel security concerns.

It is important to note that these three specific problems are interrelated. Problem 1, misaligned incentives, is the foundational issue underlying the energy security issues addressed here. As such, it will receive the most attention in the balance of this Section 2. Problems 2 and 3, operational uncertainties and insufficient day-ahead scheduling, are specific manifestations of Problem 1 (though they both have other root causes as well). We discuss each of these three problems in succession below, in order to provide clear explanations of their distinct causes and consequences.

2.2 Problem 1: Misaligned Incentives for Energy Supply Arrangements

This section examines Problem 1, focusing on existing market incentives. Specifically, we address why the ISO-administered wholesale electricity markets, in their current form, may not provide sufficient incentives for resource owners to make additional investments in energy supply arrangements – even when such investments would reduce potential reliability risks and be cost-effective for the system.

At a high level, investing in additional energy supply (*i.e.,* fuel) arrangements that meaningfully reduce the risk of shortages (and therefore the risk of high electricity prices) entails up-front costs to a generator. Yet those investments, if they meaningfully reduce that risk, will also reduce the energy market price the generator receives. The value that society places on the energy supply arrangement is based on the high price it *avoids* with the investment. However, the value the generator places on the same arrangement is based on the lower price it *receives* in the energy market with the investment. This value difference, in turn, results in a divergence between the social and private benefit of the investment – a situation we call a *misaligned incentives* problem.

In short, the misaligned incentives problem results in too little private investment in energy supply arrangements under the existing markets' incentives than is desirable from society's standpoint. And, fundamentally, to provide a long-term market solution to the region's fuel security concerns, the market design must now address that misaligned incentives problem.

To explain this problem and its root causes more precisely, a simple numerical example is helpful.

2.2.1 Example 1: One Generator

This example considers the fuel decision for a generator without a day-ahead market award. It faces an unlikely possibility that demand may be high enough for it to operate the next day, and must decide now whether or not to incur the cost of arranging fuel.

We simplify as much as possible here to focus on the essentials: A case where the cost of arranging fuel is lower than society's benefit (*i.e.*, the system's expected cost savings) from it, but that cost nonetheless exceeds the generator's expected profit. As a result, the competitive generator's rational decision is not to arrange fuel in advance of the operating day, even though society would be better off if it did.

► **Assumptions.** Consider a generator with 1 megawatt (MW) of capacity that faces uncertainty over whether or not it will operate the next day. The generator will be dispatched (if available) if demand is high, and not dispatched if demand is low. Assume there is a 20% chance of high demand, so the generator knows that it will most likely not operate. To simplify this example, we will reduce the time period in which the generator may operate (or not) to a single future hour and assume that the generator does not clear (*i.e.,* is not scheduled) in the day-ahead market.

The generator's costs depend upon whether or not it arranges fuel in advance of the operating day. Arranging fuel entails an up-front cost, and an incremental cost if the fuel is consumed the next day. We assume that if the generator arranges fuel in advance of the operating day, then it incurs an up-front cost of $40 per MW-hour (MWh). By 'up-front cost', we mean that *if* the generator decides to arrange fuel in advance, it would incur the $40 cost *regardless* of whether or not it operates the next day. And then, *in addition*, it would incur a marginal cost of $70/MWh to operate – but that marginal cost is incurred only if it does indeed operate. We summarize these cost and demand assumptions in Table 2-1 below.

Table 2-1. Cost and Price Assumptions for Example 1

	With Advance Fuel			No Advance Fuel	
	High Demand	Low Demand		High Demand	Low Demand
Up-Front Cost of Advance Fuel	$ 40	$ 40		$ -	$ -
Marginal Cost	$ 70	n/a		n/a	n/a
Energy Price (LMP)	$ 120	$ 60		$ 400	$ 60
Demand Probability	20%	80%		20%	80%

If the generator arranges fuel in advance of the operating day and the demand is high, then it can produce at a marginal cost of $70/MWh and would be paid (in real-time) an LMP of $120/MWh. That's the 'good' scenario in this example, because it will have the lowest expected total cost (as explained presently). Importantly, we will assume that if the generator does *not* arrange fuel in advance, then it will not be able to acquire fuel the next day and will not be able to operate. In that scenario, if demand turns out to be high, the ISO would have to operate another, high-cost resource (at the margin) that would set a real-time LMP of $400/MWh. That's the 'bad' scenario, as it results in higher total costs than if the generator arranged fuel in advance.[19] Finally, assume if demand is

[19] Alternatively, one can interpret the $400/MWh cost as this generator's marginal cost if it must buy spot fuel intraday (on a really bad day), if it does not make advance fuel arrangements. Either interpretation will suffice for this example.

low then the LMP would be $60/MWh so the generator would not operate, as it would be out-of-merit.

These assumptions are intended to capture the practical realities that there are up-front costs of acquiring energy supplies in advance of an operating day, *in addition* to the (marginal) cost of using the fuel itself. The $40 up-front cost could be considered the retainer (per MWh) for an intraday-notice gas supply contract with an LNG terminal, and the $70/MWh cost as the incremental cost of calling for gas in order to run the next day if the generator is dispatched. Or, the up-front cost could be considered the generator's expense for oil transportation service to accelerate replenishment of oil inventories in advance of the operating day, without which the generator would be out of fuel and not be able to run at all. Or, for a generator that is an energy storage resource, the up-front cost may account for the cost it incurs to charge-up in advance of the operating day, in order to maintain on-demand energy in ready reserve during the operating day. And so on – the practical possibilities are many. The point here is simply that there are costs of arranging input energy (*i.e.,* fuel) supplies in advance, in addition to the marginal cost of using it to produce electric energy; and, if a generator decides not to incur the costs of arranging fuel in advance, then (with *some* probability) the generator may not have fuel to operate.

Last, a note on timing: When we say 'arrange fuel in advance' in this example, we mean however far in advance of the operating day as is necessary (a day, a week, a month, or a season). Though such timing issues matter in practice, in this simplified example, *how far* in advance is not material. Rather, the fact that there are up-front, irrevocable costs to arranging fuel in advance of the operating day raises two key questions. First, would a competitive generator choose to incur them? Second, would its decision produce the best outcome for the system as well? We consider each in turn, next.

► **Society's preferred outcome.** First, let's examine what would be the most cost-effective outcome for the system. Arranging fuel in advance has an up-front cost of $40, and 80% of the time those arrangements will not turn out to be used. That might suggest arranging fuel in advance is not worthwhile, from the standpoint of a cost-effective system.

But consider the benefits. Although high demand is unlikely, it occurs 20% of the time. When it does, arranging fuel in advance means incurring a marginal cost of $70/MWh and being able to avoid dispatching an expensive resource that costs $400/MWh. The expected value of the benefit to the system (*i.e.,* the expected cost saving) from avoiding that 'bad' scenario is:

$$20\% \times (\$400/\text{MWh} - \$70/\text{MWh}) = \$66/\text{MWh}.$$

On net, that means arranging fuel is indeed worthwhile: The cost of arranging fuel in advance of the operating day is $40 for the MWh, and the expected value of the benefit is $66/MWh, so the expected value of the net benefit is $66 – $40 = $26/MWh. When the decision to arrange fuel must be made in advance of the operating day, society would be better off (*i.e.,* there is positive expected cost saving, on net) if the generator invests the $40 – even though it may not be used.

Note that in coming to that conclusion, we have not introduced any reliability considerations. We simply have concluded that from the standpoint of minimizing the system's expected cost, it is efficient to incur the up-front cost of arranging fuel in advance even though it is most likely to *not* be needed.

In this sense, from the system's standpoint, arranging fuel in advance is like insurance. Arranging fuel involves an up-front, irrevocable cost (an insurance premium), and provides a benefit in a state of the world that is *not* highly likely to occur (like most insurance claims). And yet, if that 'bad' scenario occurs, it would be very valuable to have the insurance. Finally, like a well-chosen insurance policy, in this example the *expected* benefit exceeds the expected cost of arranging fuel in advance – making the insurance it provides a desirable 'investment' from the standpoint of the system overall.

► **The generator's decision.** From a commercial standpoint, it is prudent for the generator to incur the costs of arranging fuel in advance of the operating day only if its expected net revenue is greater as a result of doing so than if it does not. In this example, if the generator does not arrange fuel, its earnings are straightforward: it will not operate the next day and so will earn nothing. Let's now consider the alterative decision to arrange fuel, which, as illustrated below, entails an expected loss to the generator. As a result, the generator would not find it profitable to acquire the fuel, though society would be better off if it did.

The cost of the 'investment' in fuel arrangements prior to the operating day is $40 up front. As before, 80% of the time demand will be low and those arrangements will not to be used. The other 20% of the time, demand is high and the generator is dispatched. In that high-demand scenario, the generator is paid the real-time LMP of $120/MWh and incurs a marginal cost of $70/MWh, earning a gross margin of $120 – $70 = $50/MWh.

That $50/MWh gross margin is more than enough to cover – on a high-demand day – the up-front cost of arranging fuel. However, the generator does not expect to operate every day. After all, demand is high only 20% of the time. That risk changes the generator's profit and loss calculus entirely.

Accounting for that uncertainty, the generator's expected net revenue if it arranges fuel is a loss. The up-front $40 investment in fuel arrangements (a cost for sure) has only a 20% chance of earning a gross margin with which to cover it. The generator's expected profit, if it arranges fuel, is a net loss of $30, as shown in Table 2-2 below. In other words, arranging fuel in advance is not financially prudent for the generation owner.

Table 2-2. Generator's Expected Net Revenue for Example 1						
			Advance Fuel		No Advance Fuel	
Generator's Market Settlement		Calculation	High Demand	Low Demand	High Demand	Low Demand
[1]	Day Ahead		$ -	$ -	$ -	$ -
[2]	Real Time	*RT LMP*	$ 120.00	$ -	$ -	$ -
[3]	Total Settlement	[1]+[2]	$ 120.00	$ -	$ -	$ -
Generator's Costs						
[4]	Advance Fuel	*F*	$ (40.00)	$ (40.00)	$ -	$ -
[5]	Marginal Cost	*MC*	$ (70.00)	$ -	$ -	$ -
[6]	Total Cost	[4]+[5]	$ (110.00)	$ (40.00)	$ -	$ -
Generator's Net Revenue						
[7]	Scenario Net Revenue	[3]+[6]	$ 10.00	$ (40.00)	$ -	$ -
[8]	Scenario Likelihood	*p* or (1-*p*)	20%	80%	20%	80%
[9]	**Expected Net Revenue**	SumProd [7]*[8]	**($30)**		**$0**	

Since there are many numbers to track in these calculations, and because we will extend this example later, Table 2-2 provides the relevant settlements and net revenue calculations for this generator for four situations: high and low demand, each with and without arrangements for fuel in advance of the operating day. To explain the generator's bottom line, as shown in row [9]:

- The bottom right-hand cell shows that if the generator does not arrange fuel, its expected profit is zero (since it does not operate), regardless of whether demand is high or low.

- The bottom left-hand cell shows that if the generator does arrange fuel, it is indeed in the red – it incurs an expected loss of $30. This is because 20% of the time, the generator will realize net revenue of $10/MWh, for an expected gain of $2/MWh. And 80% of the time, it will realize a $40/MWh loss, for an expected loss of $32/MWh. Adding the positive $2/MWh and the negative $32/MWh yields a net expected loss of $30/MWh.

The point of Example 1 is important. The market, in its current form, may not provide sufficient incentives for resource owners to invest proactively in energy supply arrangements – even when such investments would be cost-effective and yield expected net benefits to the system.

2.2.2 Reliability Risks and Problem 1

In the prior example, the generator's rational decision is not cost-effective for society. There is a true market failure to incent efficient outcomes, causing higher expected costs to society as a result. However, that is not the only potential problem.

Let's now modify the prior example slightly: Assume next that if the generator does not arrange fuel in advance of the operating day and demand is high, then the system will not have sufficient resources to avoid a shortage of reserves. In this 'bad' scenario, the real-time price for reserves (in shortage) would be $1,000/MWh and the LMP (we'll assume) would be higher, at, say $1,400/MWh. If the generator does arrange fuel, however, we'll assume the same outcomes as before with, no reserve shortage.

For simplicity, we will first analyze this scenario based on the energy market's incentives and outcomes. There is also an impact (in this new scenario) to consider from capacity market performance incentives. That involves additional calculations, which we will subsequently address further below.

From the generator's standpoint, nothing changes due to the now-higher LMP that may occur if it does *not* arrange fuel. It was never paid the LMP that prevails in the 'bad' scenario (since it does not operate when that occurs) – and therefore that high LMP scenario does not incent it to invest in fuel supply arrangements. In terms of the numbers in Table 2-2 above, the value of the real-time LMP in the cases with 'No Advance Fuel' (the right-hand columns) produces no revenue for the generator. And, if it does arrange fuel in advance of the operating day (the left-hand columns), and by so doing prevents the reserve shortage, it would still have an expected loss of $30/MWh.

Things are *not* the same from society's standpoint in this new situation, however. From that perspective, the benefit of arranging fuel in advance is now much larger. Here, we will assume that the costs to society of the reserve shortage are the sum of the marginal alternative generator's cost (again assumed to be $400/MWh) and the 'cost' at which the market values a reserve shortage (at the margin), which is presently $1,000/MWh.[20] That means arranging fuel in advance avoids incurring, if high demand occurs, a cost of $1,400/MWh, and instead using $70/MWh energy (at the margin) to meet demand. That 'good' scenario has an expected benefit (expected cost saving) to the system of:

20% × ($1,400/MWh – $70/MWh) = $266/MWh.

On net, that means arranging fuel is indeed worthwhile for the system: The cost of arranging fuel in advance of the operating day is $40/MWh, and the expected value of the benefit of doing so is $266/MWh, for a *net* expected benefit of $266/MWh – $40/MWh = $226/MWh.

The point here is simple. If a generator's decision to arrange fuel in advance is material enough to impact – with *some* probability – whether or not the system experiences a reserve or energy shortage, then the divergence between society's and the generator's incentives *gets worse.* That is, the problem of the misaligned incentives does not have only adverse efficiency consequences. It can also have adverse reliability consequences. As this case shows, the competitive generator's rational decision is again not to arrange fuel, but society would be even better off – and the system's reliability risk lower – if it did. The more severe the consequences of the generator's decision, the more its incentives are misaligned from society's.

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[20] This $1,000/MWh value is an existing administrative real-time reserve shortage price, defined in the Tariff as a Reserve Constraint Penalty Factor, and associated with the system's real-time minimum total operating reserve requirement. *See* Tariff Section III.2.7A.

We should note again here that this case with the potential reserve shortage does not incorporate other market incentives that are important in New England. Since June 1, 2018, resources that supply energy face stronger marginal incentives to perform under the ISO's two-settlement capacity market design (Pay for Performance or PFP). We address how PFP affects these situations in greater detail, further extending this example, below.

2.3 Insights: Problem 1's Consequences and Implications

Although these examples are simple illustrations of a market design problem, they identify several key points that hold generally. As noted previously, investments in energy supply arrangements can be characterized as insurance, in the sense of paying more to achieve more reliable outcomes. That's logical enough, but isn't the whole story.

In these examples, investments in energy supply arrangements *lower* the system's expected total cost – paying *less* overall – to achieve equally (or more) reliable outcomes. That's a far more sweeping observation. It says the system would meet demand more cost-effectively overall if the generator made the up-front investment to arrange fuel, even though the arrangement may not be used. However, under the current market design, making such fuel supply arrangements may not be financially prudent from the generator's standpoint of maximizing its expected net revenue. And the generator is acting perfectly rationally and competitively (offering at its marginal cost) throughout.

What is the crucial insight here? Simply that the market price for energy – what consumers value consuming – is impacted by the supplier's investment in fuel arrangements (at least, with positive probability). Thus, in taking a costly action (incurring the up-front cost of arranging fuel), society benefits more than the generator does. The difference between those benefits (to the generator) and cost savings (to society) is the misaligned incentives problem, and it results in higher expected costs to society as a result.

Equally important, this misaligned incentives problem becomes worse precisely when the region's fuel security constraints are tightest. In such conditions, the social benefits of arranging energy supplies in advance can be large, because of the high production costs and prices society *avoids* by doing so (the $400/MWh in the first example). And we should be willing to spend more up-front to mitigate a risk when its likelihood is greater, or when its consequences (if it does occur) are more severe. Unfortunately, those higher-risk conditions are precisely when the misalignment problem is at its worst: since the generator does not internalize (that is, is not the beneficiary of) the high price that is avoided by its investment in fuel arrangements, the divergence between its private incentives and society's preferred outcome is greatest precisely society would benefit the most.

In sum, the misaligned incentives problem described here will not solve itself. In fact, as the tight fuel infrastructure constraints in New England show no signs of dissipating in the foreseeable future,[21] the underlying risk likelihood appears to be growing over time – and, if unaddressed, the consequences of the misaligned incentives problem will only get worse.

2.4 Why Doesn't Pay-for-Performance Solve This?

Resources in the New England power system are incented, in real-time, not only by the real-time LMP, but also by a performance incentive created by the ISO's Pay-for-Performance capacity market rules. The PFP market rules will impact a resource's incentives to arrange fuel in advance of the operating day whenever the conditions demarking a PFP event, known as a Capacity Scarcity Condition, may occur.

As an initial observation, note that in the first analysis of Example 1 in Section 2.2.1, there is no reserve deficiency, and the PFP market rules would not change any of the calculations in Table 2-2. Yet that example shows how the energy market may not provide sufficient incentives for resource owners to invest proactively in energy supply arrangements – even when such investments would be cost-effective and yield expected net benefits to the system. This market failure to produce efficient, socially beneficial investment decisions would not be altered by PFP in that case, as it stands wholly apart from the circumstances when PFP would apply.

In more extreme situations where there are potential shortages of energy or reserves (as in Section 2.2.2), the impact of PFP on these incentives is more nuanced. Generally, even when there may be a reserve shortage, PFP helps, but it does not fully solve, Problem 1. To illustrate why, we next extend the prior numerical examples.

2.4.1 Example 1 and Pay-for-Performance

We'll build on the extended version of Example 1 discussed in Section 2.2.2, where there is a potential reserve shortage, and now layer in the additional settlements associated with PFP.

► **Additional assumptions.** To capture the impact of PFP, assume the generator has a Capacity Supply Obligation of 1 MW (its same capacity as before). During the hour considered in this analysis, assume the system's Balancing Ratio (BR) is 80% (that exact value is not critical to what follows), and that the Performance Payment Rate (PPR) is equal to its current Tariff value of \$3,500/MWh.[22]

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[21] *See* Brandien Testimony at pp. 23-26.

[22] Pay for Performance is a two-settlement capacity market design, with both a forward payment (set upon assuming a Capacity Supply Obligation) and a spot (or real-time) payment for deviations (calculated for each resource during a Capacity Scarcity Condition). Under PFP, the spot payment is known as the performance payment, and the Balancing Ratio and the Performance Payment Rate are both components of the performance payment calculation. The Performance Payment Rate is the design's Commission-approved, proxy real-time price – the rate at which deviations from forward obligations are settled. The Balancing Ratio scales a resource's forward obligation such that instead of being an obligation for a fixed quantity of capacity, it is an obligation to provide a specific share of the system's needs during the scarcity condition. Generally, if the scarcity condition occurs on a high-load day, the Balancing Ratio will be higher, and the participant's actual performance will be assessed relative to a higher percentage of its forward obligation; if the scarcity

We again assume that if the generator does not arrange fuel in advance of the operating day and demand is high, the system will not have sufficient resources to avoid a shortage of reserves. In that 'bad' scenario, as before, the LMP would be $1,400/MWh. If the generator does arrange fuel, however, then (in that 'good' scenario) we have the same outcomes as before with no reserve shortage. All other assumptions, including the generators' up-front and marginal costs of fuel, and the likelihood of high or low demand, are the same as those summarized in Table 2-1, above.

► **The generator's decision.** In this revised example, if the generator does arrange fuel in advance of the operating day, nothing changes from the outcomes summarized in the left-side columns of Table 2-2 previously. There is no reserve shortage: if demand is low the generator does not operate, and if demand is high it operates and earns a gross margin of $120 – $70 = $50/MWh. As before, the expected value of its gross margin is 20% × $50/MWh = $10/MWh, which is not enough to cover its $40 up-front cost. Thus, as shown in the bottom row of Table 2-2, if the generator arranges fuel in advance, it expects to incur a net loss of $30.

Let's now consider the alterative decision to not arrange fuel in advance of the operating day. In this case, the generator no longer has an expected profit of zero when it does not run. Instead, it will incur a non-performance charge in PFP settlements.

Table 2-3 below summarizes the relevant calculations. The general PFP settlement formula (in simple terms) is

$$\textit{Performance Payment} = \text{PPR} \times (\text{A} - \text{BR}) \times \text{CSO} \times \textit{event duration}$$

where A is the resource's output (in MWh). In this example, A is zero if the generator does not make arrangements for fuel, its CSO is 1 MW, and the event duration is assumed to be one hour. Therefore, the performance payment would be a charge of:

$$\$3{,}500/\text{MWh} \times (0 - 80\%) \text{ x } 1 \text{ MW CSO} \times 1 \text{ hour} = -\$2{,}800.$$

This is shown in row [4] of Table 2-3, for the scenario (column) with high demand and no advance fuel.

Of course, whether or not that occurs depends if demand is high or not. As before, if demand is low, there is no reserve shortage, the generator is not called to operate, and its net revenue in the low-demand scenario is zero. However, there's a 20% chance of high demand and, without the fuel to operate, it would then incur the PFP non-performance charge of $2,800. The expected value of the generator's net revenue if it does not make arrangements for fuel in advance of the operating day is therefore

condition occurs on a low-load day, the Balancing Ratio will be lower, and the participant's actual performance will be assessed relative to a lower percentage of its forward obligation. For a more detailed explanation of the PFP rationale and mechanics, *see* Filings of Market Rule Changes To Implement Pay For Performance in the Forward Capacity Market, FERC Docket Nos. ER14-1050-000, -001 (filed January 17, 2014).

(20% × (– $2,800)) + (80% × $0) = – $560.

See the bottom row of Table 2-3. Viewed this way, the profit maximizing decision – which, in this case, is a *loss minimizing* decision – is laid bare: Arranging fuel involves an expected net loss of $30, but not arranging fuel involves an expected net loss of $560. Given these stark alternatives, the generator's prudent course of action is to incur the up-front cost of arranging fuel.

Table 2-3. Generator's Expected Net Revenue for Example 1 with PFP

			Advance Fuel		No Advance Fuel	
Generator's Market Settlement		Calculation	High Demand	Low Demand	High Demand	Low Demand
[1]	Day Ahead		$ -	$ -	$ -	$ -
[2]	Real Time	*RT LMP*	$ 120	$ -	$ -	$ -
[3]	PFP Performance Pmt	*PPR * (A - BR)*	$ -	$ -	$ (2,800)	$ -
[4]	Total Settlement	[1]+[2]+[3]	$ 120	$ -	$ (2,800)	$ -
Generator's Costs						
[5]	Advance Fuel	*F*	$ (40)	$ (40)	$ -	$ -
[6]	Marginal Cost	*MC*	$ (70)	$ -	$ -	$ -
[7]	Total Cost	[5]+[6]	$ (110)	$ (40)	$ -	$ -
Generator's Net Revenue						
[8]	Scenario Net Revenue	[4]+[7]	$ 10	$ (40)	$ (2,800)	$ -
[9]	Demand Probability	*p* or (1-*p*)	20%	80%	20%	80%
[10]	**Expected Net Revenue**	SumProd [8]*[9]	**($30)**		**($560)**	

In that sense, PFP helps to solve Problem 1, as suggested previously. As before, society is better off if the generator arranges fuel in advance of the operating day, as it helps to avoid the high costs and reliability risks of a reserve shortage. And the generator is incented to do so, because of the high financial price to be paid if it is unable to perform when a reserve shortage occurs.

2.4.2 So Why Doesn't PFP Fully Solve the Problem?

There is much more to the PFP question we started with. As noted at the outset, PFP helps, but does not fully solve, Problem 1. Let's now consider a minor change to the preceding scenarios that will reverse the foregoing result – and show how PFP does not fully solve the problem with (arguably) more "realistic" risk likelihoods.

The preceding PFP example had a number of simplifying assumptions to keep the calculations simple. One seemingly unrealistic assumption is that there would be a 20% chance of a reserve shortage (absent the fuel arrangements). Capacity Scarcity Conditions, in practice, are rare events. Let's now see what happens if we re-do the preceding calculations assuming that there is only a 1%

chance of a reserve shortage (absent the fuel arrangements). That lower risk level will change things significantly, and show that PFP does not fully solve Problem 1.

To expedite the narrative, Table 2-4, below, shows the full settlements and expected net revenue for the generator with PFP under the same assumptions as before, but now with only a 1% chance of high demand. The bottom row corresponding to 'with fuel arrangements' now produces an expected loss of $39.50, which is close to the $40 up-front cost of arranging fuel. That $40 is now a total loss 99% of the time, offset by a slim 1% chance that demand is high, the unit runs, and makes its $50 gross margin. The generator's net expected revenue, if it arranges for fuel in advance of the operating day, is thus (1% × $50/MWh) – $40 = – $39.50/MWh, a net loss.

Table 2-4. Generator Expected Net Revenue for Example 1 with PFP

			Advance Fuel		No Advance Fuel	
Generator's Market Settlement		Calculation	High Demand	Low Demand	High Demand	Low Demand
[1]	Day Ahead		$ -	$ -	$ -	$ -
[2]	Real Time	*RT LMP*	$ 120	$ -	$ -	$ -
[3]	PFP Performance Pmt	*PPR * (A - BR)*	$ -	$ -	$ (2,800)	$ -
[4]	Total Settlement	[1]+[2]+[3]	$ 120	$ -	$ (2,800)	$ -
Generator's Costs						
[5]	Advance Fuel	*F*	$ (40)	$ (40)	$ -	$ -
[6]	Marginal Cost	*MC*	$ (70)	$ -	$ -	$ -
[7]	Total Cost	[5]+[6]	$ (110)	$ (40)	$ -	$ -
Generator's Net Revenue						
[8]	Scenario Net Revenue	[4]+[7]	$ 10	$ (40)	$ (2,800)	$ -
[9]	Demand Probability	*p* or (1-*p*)	1%	99%	1%	99%
[10]	**Expected Net Revenue**	SumProd [8]*[9]	**($39.50)**		**($28.00)**	

What if the generator does not arrange fuel in advance of the operating day? As before, if demand is high, there is a reserve shortage and the generator would incur the PFP performance charge of $2,800. However, that has only a 1% chance, so the expected value of the generator's PFP performance charge is now comparatively trivial: 1% × $2,800 = $28, as indicated on the right side of the bottom row of Table 2-4.

Comparing the two cases, the generator's prudent financial decision is again the loss-minimizing one. Arranging fuel involves an expected net loss of $39.50, but not arranging fuel – which now is very unlikely to be used – involves an expected net loss of $28. The generator is financially better off, given these alternatives, if it does *not* incur the up-front cost of arranging fuel. Yet, as before, society would be better off if it did: The system's outcomes would be more cost-effective, and the reliability risk of a reserve shortage would be reduced. The misalignment problem remains.

In that sense, PFP does not fully solve Problem 1. Even with PFP, society faces a lower reliability risk if the generator arranges fuel in advance of the operating day, but those arrangements may not be consistent with the generator's commercial interest (particularly if the likelihood of reserve shortages is small). The reason PFP does not fully solve Problem 1 is not complicated. As this example illustrates, when the risks of a reserve shortage are low, the incentive PFP creates for performance are significantly muted – too muted for it to be privately financially beneficial for the generator to incur the up-front costs of arranging fuel, the costs of which will be a total loss most of the time.[23]

2.5 Insights: The Misalignment Problem's Root Causes

Example 1 shows that even when up-front investments in resources' energy supply arrangements would be cost-effective from society's standpoint, the current market design may not provide sufficient financial incentives for competitive generation owners to undertake them.

Stated generally, Problem 1 has three root causes, all of which are at work in the mechanics of Example 1 (and variants thereof) discussed previously. These three root causes are:

Root Cause 1: **Uncertainty** over whether the generating unit will be in demand, or not.

Root Cause 2: **Irrevocable (*i.e.,* up-front) costs** of making arrangements for fuel, which must be incurred in advance of learning whether the generator will be in demand (asked to operate) or not.

Root Cause 3: **Materiality of energy supply arrangements,** in the precise sense that if the generator does make arrangements for fuel in advance, then with some probability (*i.e.*, when the generating unit is in demand), the real-time price for energy will be lower, or reliability will be better, than if it does not.

The first two of these root causes are conditions commonly affecting fuel supply arrangements for much of the generation fleet – such as the oil-fired resources and higher-cost (higher heat-rate) gas-fired resources that do not often clear in the day-ahead energy market. As a result, their owners face uncertainty over whether those resources will be called to operate in real-time (and, more broadly, uncertainty over how often they may run). These causes have existed relatively consistently for many years.

The third root cause merits emphasis. In simple terms, if the existence of advance fuel supply arrangements impacts whether real-time energy prices are lower, or whether reliability outcomes

[23] Of course, one might note – accurately – that if lack of fuel to operate was widespread in the generation fleet when those generators are 'in demand,' then the likelihood of reserve shortages may no longer be small. And indeed, as the earlier example (when there was a 20% risk of a reserve shortage) shows, if the likelihood of a reserve shortage is higher, then the impact of PFP will be far more powerful. It then becomes a better decision to arrange fuel proactively to ensure the generator can operate. So, in a sense, this problem is 'self-correcting' because PFP would tend to induce resources to arrange fuel to ensure they can perform *if* the frequency of reserve shortages becomes high enough. That, however, should be viewed as a Pyrrhic victory from reliability standpoint.

are improved, then those arrangements are material. And this materiality is one important cause of the misaligned incentives problem. While it may seem too obvious to state, if this were not the case – that is, if the presence of advance fuel arrangements had no effect on prices or reliability – then the region would not face an energy security problem in the first place.

To see why, consider that if – counterfactually – the presence of such arrangements was *not* material to prices or reliability, then in all cases there must be *another* resource available at the same time, and at the same offer price (or less), that could serve the same increment of demand. And in that case, there is neither a market efficiency problem nor a reliability problem: the system would always have another resource to meet incremental demand, at the same cost. In short, for the misaligned incentives problem (Problem 1) to arise, generators' energy supply arrangements must impact potential real-time outcomes in the precise sense that without them, there is a chance of a higher real-time price, a higher likelihood of a shortage (of reserves or of energy) – or both.

► **The evolution of the system in recent years has made the materiality of energy supply arrangements much more significant.** In the past, generators commonly had large, ready stockpiles with which to fuel a run whenever committed or dispatched. If some day-ahead scheduled resource wasn't able to operate unexpectedly (for any reason), there were always sufficient energy stocks to dispatch up another generator in its place. This was true provided the system was committed (or could be supplementally committed) to have sufficient capacity for the peak hour, a main day-ahead operating plan focus in the past.

Now, with constrained fuel infrastructures, retirements of generators with ample fuel storage, and evermore just-in-time generation from renewable technologies, it is no longer assured that if a day-ahead scheduled resource isn't able to operate unexpectedly (for any reason), there will always be sufficient energy to dispatch up another generator in its place – at a similar or small change in the real-time LMP. Instead, if a generator has no fuel to operate during cold weather conditions, then there is an increasing likelihood that the real-time LMP will be set by either (*a*) an expensive next resource 'in the stack', or (*b*) scarcity pricing that signals a deficiency in the system's supply of energy and reserves.

For these reasons, as New England's resource mix has evolved toward technologies with predominantly just-in-time energy sources, the materiality of energy supply arrangements has become a more significant potential concern than in the past. Moreover, we do not expect this issue to abate in the future, given the generation fleet's dramatic shift to more and more just-in-time resources.[24]

[24] *See* Brandien Testimony at pp. 23-26.

2.6 Problems 2 and 3: Operational Uncertainties and Insufficient Day-Ahead Scheduling

We now turn to Problems 2 and 3, concerning operational uncertainties and insufficient day-ahead scheduling. As noted throughout the foregoing sections, with the region's growing dependence on just-in-time energy sources and its constrained fuel delivery infrastructure, resources that do not expect to run the next day (*e.g.,* that do not receive an award in the day-ahead market) may not have sufficient incentives to make costly energy supply arrangements in advance.

This precipitates the concerns identified as Problem 2 and Problem 3. Problem 2, operational uncertainties, arises when there may be insufficient energy available to the power system to withstand an unexpected, extended (multi-hour to multi-day) large generation or supply loss, particularly during cold weather conditions. Problem 3, insufficient day-ahead scheduling, occurs when the day-ahead market's outcome produces next-day generation and (net) import energy schedules that are insufficient to cover the region's forecast energy demand next operating day. This commonly arises when market participants procure less energy in the day-ahead market than the ISO's forecast of their real-time demand for the next day.

This analysis builds on Problem 1 (misaligned incentives) and the insights from the prior section, but now adds the practical considerations of the power system's operational needs.

2.6.1 Three Essential Reliability Services

As explained in the Brandien Testimony, the ISO is increasingly concerned there could be insufficient energy available to the New England power system.[25] There are several distinct ways in which the system may face a 'gap' between the energy available and the energy required to ensure reliable daily system operations, as summarized next.

Currently, the ISO relies upon much of the generation fleet's capabilities, above and beyond their day-ahead energy awards, for the essential reliability services necessary to fill such energy gaps. But the ISO does not currently procure or compensate for these types of service capabilities on a day-ahead timeframe. This, combined with the region's growing dependence on just-in-time energy sources and its constrained fuel delivery infrastructure, leaves the region vulnerable in a way that must be addressed.[26]

These energy gaps – and the resource capabilities that the ISO relies upon to fill them – fall into three broad operational categories.

A. The energy gap between day-ahead market schedules and forecast energy demand. This gap arises when the total energy cleared in the day-ahead market from physical supply resources (generation and net imports into New England) are less than the ISO's

[25] *See* Brandien Testimony at pp. 23-24.

[26] *See, generally,* Brandien Testimony at pp. 24-26.

forecast energy demand, in one or more hours, during the next (operating) day. This gap is Problem 3, insufficient day-ahead scheduling.

Under applicable reliability standards, the ISO's operating plan for the next day is intended to ensure there is sufficient energy to cover the forecast energy demand each hour – not simply the level of demand cleared in the day-ahead energy market.[27] Therefore, the energy to cover this gap is supplied through the dispatch and post-market commitment of other resources operating above, or that did not receive, a day-ahead market award.[28]

Given the inefficiently low incentives for resources without day-ahead energy schedules to arrange fuel in advance of the operating day (as explained throughout this Section 2), with these Energy Security Improvements the ISO is creating a new energy imbalance reserve ancillary service in the day-ahead market. As discussed in detail below, this will strengthen the incentives for *all* of the resources needed to satisfy forecast energy demand – a requisite component of a reliable next-day operating plan – to arrange energy supplies in advance of the next operating day.

B. Operating reserves for fast-start and fast-ramping generation contingency response. This gap arises when there is a sudden, unanticipated supply loss during the operating day.[29] This gap is directly related to Problem 2 – operational uncertainties.

Energy to cover this gap comes from resources that the ISO relies upon for real-time operating reserves. These include both off-line (fast-start) generation and the unloaded 'upper blocks' of on-line generation (called 'spinning' reserves). The ISO relies upon these capabilities to ensure the system is prepared to promptly restore the system's energy balance (consistent with the timeframes established in applicable reliability standards).[30]

Because unanticipated supply losses are just that – unanticipated – the resources that the ISO relies upon for this purposes have no reason to expect to operate (or to operate at levels above their day-ahead schedules) the next day. Accordingly, for the reasons explained in Section 2.5, they too face inefficiently low incentives to arrange fuel in advance of the operating day. With these Energy Security Improvements, the ISO is creating a new day-ahead Generation Contingency Reserve service that will strengthen the incentives for such resources to ensure they have energy supplies in advance of each operating day.

C. Replacement energy. This gap occurs when a resource scheduled in the day-ahead energy market is unexpectedly unable to operate for an extended (multi-hour to multi-

[27] *See* Brandien testimony at pp. 18-19.

[28] *See* Brandien Testimony at pp. 17-18.

[29] *See* Brandien Testimony at pp. 8-9.

[30] *See* Brandien Testimony at pp. 7-10.

day) duration. This is another manifestation of Problem 2 – operational uncertainty. In this situation, the ISO must again dispatch online resources above their day-ahead schedules, or supplementally-commit offline resources without day-ahead schedules, to supply sufficient energy to cover the energy gap through the balance of the day (and, if applicable, the day following).

As indicated in the Brandien Testimony, "In [New England's] increasingly energy-limited system, it is uncertain whether there will always be other resources capable of responding with sufficient energy to permit the power system to withstand a sudden, extended (multi-hour to multi-day) loss of a large generator or other supply source."[31] Given the analysis of Problem 1, that operational risk should come as no surprise: the current market design has no products to provide resources with the economically-appropriate incentives, or the compensation, to ensure they maintain sufficient energy supplies to serve the system's replacement energy needs for the balance of the operating day and beyond. Accordingly, in these Energy Security Improvements, the ISO is creating a new day-ahead Replacement Energy Reserve service that will strengthen the incentives for the resources the ISO relies upon for this purpose in its operating plans.

As summarized in the Brandien Testimony, these resource capabilities comprise three essential reliability services that the ISO relies upon in its operating plans to meet its reliability standards and criteria.[32] We will distinguish among them in this paper because they require different resource capabilities in order to cost-effectively address potential energy gaps that arise on, and persist for, different timeframes.

► **Implications.** Our present point is that the ISO relies upon much of the generation fleet's capabilities – above and beyond their day-ahead market awards – to satisfy the next-day operating plan's requirements and to maintain a reliable power system. For the reasons explained in detail in the Brandien Testimony, filling these energy gaps can no longer be an incidental aspect of the ISO's markets; these are indeed essential reliability services.[33] Resources, however, are not currently compensated in the day-ahead market for these capabilities. Indeed, since its inception, ISO New England has had no day-ahead ancillary services markets at all.

Instead, presently the ISO employs (unpriced) constraints in its day-ahead market unit commitment process to help ensure that there will be sufficient capability to cover the next-day forecast energy demand (category A) and sufficient operating reserves each hour of the next day (category B); and it employs out-of-market procedures and reliability-commitment tools (after the day-ahead market) to evaluate and ensure there will be sufficient resources to cover all three of these essential reliability services (categories A and C, respectively).

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[31] Brandien Testimony at p. 26.

[32] *See* Brandien Testimony at pp. 17-18, 26-28.

[33] *See* Brandien Testimony at pp. 17-18.

These out-of-market practices are increasingly problematic. Given the region's growing dependence on just-in-time energy sources and its constrained fuel delivery infrastructure, the ISO is increasingly concerned that the resources the system relies upon for these essential reliability services may not have energy supply arrangements that will enable them to operate on days when they have no reason to expect to run (or to run above or longer than their day-ahead market award, if any). In that event, if the system experiences an unexpected, extended large generation or supply loss during cold weather conditions – particularly, if it occurs when renewable resources' production capability is low (when the sun is down or the winds are calm) – the region may not have the energy needed to reliably fill the ensuing energy gap.[34]

2.6.2 Many Resource Types Can Potentially Provide These Essential Reliability Services

Importantly, the most cost-effective set of resources to fill the energy gaps described in categories A, B, and C can (and does) vary daily. It depends on the day-ahead cleared generation pattern, the cleared and forecast demand profile over the course of the day, available resources' lead-times and capabilities, weather and intermittent-resource energy production (actual and forecast), constraints on natural-gas pipelines supplying electric generation, and so on.

As examples, the types of existing resources the system may rely upon to provide these three essential reliability services include:

a) off-line fast-start dispatchable generators (generally, hydro-electric and distillate-fueled combustion turbines and internal-combustion units), which infrequently receive day-ahead energy market awards and are dispatched during the operating day as circumstances require;

b) higher-cost 'blocks' of combined-cycle generators that receive day-ahead awards below their maximum output (or possibly for a lower-output configuration), which the ISO may dispatch higher or schedule longer than their present day-ahead market energy schedules for the operating day;

c) higher heat-rate, combined-cycle generators that did not clear in the day-ahead market and may be committed (after the day-ahead market or, if necessary, intra-day) to satisfy the load forecast or for replacement energy; and

d) long lead-time oil-steam units, in certain situations (*e.g.* cold weather conditions) when these resources can be lower-cost than gas-fired alternatives or when gas pipeline constraints preclude gas-fired resources from serving the system's load-balancing and replacement energy needs.

► **Implications.** There is not a static set of resources, or a specific set of technologies, that is most cost-effective in meeting the system's operational needs for the three essential reliability services summarized above. It varies from day to day. Moreover, which specific resources the ISO may rely

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[34] *See, generally*, Brandien Testimony at pp. 23-26.

upon for these purposes as part of a reliable next-day operating plan depends on the generation commitments and energy schedules awarded in the day-ahead energy market.

Looking forward, the ongoing evolution in New England's resource mix will also change the set of resources the system potentially relies upon for these same operational purposes. Many of the resources in category (d) (long lead-time oil-steam units) the ISO considers at risk for retirement, which may subsequently leave the combined-cycle generators in categories (b) and (c) as the predominant resource types to satisfy the system's load-balance and replacement energy needs. Moreover, with time, new technologies may change this mix further. For example, as new storage-based technologies become more prevalent, and their economics and energy sustainability improves, the resources that prove most cost-effective to satisfy these same operational purposes may shift to make use of those technologies.

The broader point here is that in considering how to ensure sufficient revenue so that the resources that satisfy these operational purposes each day invest in reliable energy supply arrangements (to operate above their day-ahead awards), there isn't a specific resource 'type' or technology at issue. Rather, it is important that compensation be sufficiently dynamic to reward the resources that are the most cost-effective on any given day.

2.6.3 Magnitude of These Energy Gaps

The New England system has over 30 gigawatts (GW) of capacity resources that supply power, experiences a net summer peak demand of approximately 25-26 GW, and net power demand of approximately 21-22 GW or so during cold weather conditions. For context, it is useful to clarify how much of that supply capability the ISO typically relies upon for the three operational purposes described above.

The short answer is that the total quantity of power and energy the ISO relies upon to satisfy these three operational purposes varies from day to day. In recent years, day-ahead cleared energy demand, after subtracting net virtuals (*i.e.*, cleared virtual supply less virtual demand), is often within a few percent of the load forecast in most hours. However, that gap can amount to many hundreds of MWh (per hour) and occasionally over a GWh.[35] When the load-balance gap is large, the ISO relies on resources' capabilities above their day-ahead awards to cover the load forecast (category A above), and may supplementally commit (after the day-ahead market) additional generation for this purpose.

Operating reserves (category B above), currently has formulaic requirements applied in the real-time energy market. Total operating reserves for prompt supply-loss contingency response are typically in the range of 2.2 to 2.6 GWh per hour, and are based on the projected size of the largest

[35] *See* Section 6.1.2.

and next-largest source-loss contingencies each day. The specific amount required (for the peak hour of the operating day) is reported daily in the ISO's *Morning Report.*[36]

Replacement energy (category C above) is more complex, as it depends on the scheduled energy profile of the system's largest contingencies over the course of the day. This can vary from hour to hour if the largest contingency is, for example, an external interface with an hourly-varying import energy schedule for the next day; or it may be constant over the course of the day if the largest contingency is a fully-loaded resource with constant scheduled power output over time (such as a nuclear unit). As explained in greater detail in Section 7.3 below, the replacement energy needed for timely contingency reserve restoration in the New England system is commonly approximately 1.3 GWh.

The summary point here is that, on some days, the total capability that the ISO relies upon to satisfy the foregoing three operational purposes can be substantial – commonly 4 GWh (per hour) or more of generation capability. The total quantities required to provide a reliable next-day operating plan vary from day-to-day, and these quantities are objectively based on the forecast demand profile and the system's largest potential single-source energy losses during the course of the operating day. These are capabilities that are not remunerated in the day-ahead market today, however, as they are provided by resources' capabilities above and beyond the level of their day-ahead energy market awards.

2.7 Implications for Energy Security

The preceding discussion of energy gaps as they arise today highlights the essential reliability services that are most needed to address the three problems (Problems 1, 2, and 3) examined previously in Section 2. As illustrated in Example 1 above, and in Example 2 below, generating resources that do not expect to run the next day (*e.g.,* that do not receive, and do not expect to receive, an energy schedule in the day-ahead market) may not find it financially prudent to make costly energy supply arrangements in advance – as they may often not be used, resulting in a financial loss.

In contrast, consider resources that face much less uncertainty over their energy production. Since the implementation of the Energy Market Offer Flexibility market design improvements,[37] the ISO has not observed significant problems with gas-fired resources that clear in the day-ahead market failing to have sufficient fuel to meet their day-ahead energy market schedules. In the winter, the gas-fired resources that clear in the day-ahead energy market tend to be among the system's more

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[36] The Morning Report is available at https://www.iso-ne.com/markets-operations/system-forecast-status/morning-report.

[37] *See ISO New England Inc., et al.,* Energy Market Offer Flexibility Changes, Docket No. ER13-1877-000 (July 1, 2013) (incorporating in the Tariff energy market offer-flexibility enhancements to allow market participants to modify their offers to supply electricity on an hourly basis within the operating day to better reflect changing fuel costs and opportunity costs in offers). *See also ISO New England Inc., et al.,* 147 FERC ¶ 61.073 (2014) (accepting, subject to conditions, the energy market offer-flexibility enhancements).

efficient (lower heat-rate) resources. As a general rule, more efficient resources face less uncertainty over whether (and for how many hours) they will clear each day. Moreover, generating units that have a superior heat rate (lower marginal cost of production) will be willing to spend the most each day to acquire whatever natural gas is available for electricity generation in New England.[38]

At the opposite end of the spectrum, the situation can be quite different for the resources that the ISO relies upon to manage uncertainty – that is*,* for the essential reliability services discussed in Section 2.6.1. These resources that provide these services are most likely to face inefficiently low market incentives to invest in the energy supply arrangements necessary to provide these capabilities reliably – even when such arrangements would be a cost-effective means to reduce reliability risks. That is the central energy security challenge facing New England's electricity markets.

It is instructive to examine further why we focus on these essential reliability services, and the fuel supply incentives for resources needed to achieve them. First, as noted earlier, resources do not receive a day-ahead market award, nor any day-ahead revenue, for the capabilities that the ISO relies upon to meet forecast-load imbalances, operating reserves, and replacement energy requirements. Moreover, the frequency with which the ISO will call upon any specific resource to provide these capabilities is inherently difficult for those resource owners to predict – as, by their very nature, these capabilities are used to manage uncertainties. Thus, these resources face considerable production uncertainty (the first of the three root causes of the misaligned incentives problem, discussed in Section 2.5 above) over whether and how often they will be called to operate, both day-to-day and over the season as a whole.

Second, there are up-front costs to proactively arrange the energy supplies (the second of the root causes discussed above) that will ensure a resource can operate if called unexpectedly during, or just prior to, the operating day. Examples include arrangements by natural gas-fired generators to procure and maintain LNG inventories at existing LNG facilities in the Northeast (for use when the interstate gas pipelines from the west are constrained), and making advance arrangements to enable fuel oil supplies to be promptly replenished at the region's dual-fuel (oil and gas), distillate, and heavy-oil power plants. These types of arrangements entail up-front costs to acquire fuel (or contractual rights thereto) that can then be used by the generator 'on demand.' Yet, for the reasons shown in Sections 2.2 through 2.5, in today's market construct it is generally unprofitable to incur the costs of arranging energy supplies that a resource does not expect to use.

Third, the beneficial impact to the system from those types of energy supply arrangements (or materiality, the third of the root causes discussed above) is likely to be particularly pronounced for the resources that the ISO relies upon for forecast-load imbalances, operating reserves, and replacement energy requirements. The reason is that the system tends to rely upon those

[38] Moreover, owners of efficient gas-fired generators that face relatively little uncertainty over their daily production during the winter commonly follow business strategies that hedge (financially) much or most of their generators' output in advance of the winter, which makes the owner relatively insensitive to (that is, not adversely impacted by) an unexpectedly high spot price of natural-gas when scheduling fuel for their resources each day.

capabilities the most when it experiences adverse conditions: when gas pipelines are highly constrained, when renewable resources experience adverse weather, or for any other reason that lead system conditions to change markedly from those anticipated day-ahead. During such conditions, whether or not a generator providing these capabilities has the energy to operate may have a more significant impact on market prices – and in extreme conditions, impact a potential reserve or energy shortage – than during normal operating conditions. That is, the resources providing these operational capabilities are most likely to be called upon during periods when their energy supply arrangements (or absence thereof) matter to market outcomes and to system reliability.

The bottom line is that the resources that the system relies upon for the three essential reliability services discussed in Section 2.6.1 are those we expect to be most adversely affected by the misaligned incentives problem (Problem 1). However, while it may be a cost-effective means to reduce reliability risks for these resources to invest in additional energy supply arrangements, the current market construct provides inefficiently low incentives to do so. As a result, the ISO is increasingly concerned that the system is relying upon resources for forecast-load imbalances, operating reserves, and replacement energy capabilities that have no day-ahead obligations – and, as a result, may not have sufficient energy supply to operate if called.

These observations imply it would be beneficial to improve today's day-ahead energy market construct so that the future resource mix will invest in energy supply (*e.g.*, fuel) arrangements that ensure these essential capabilities remain reliable and available to the power system each operating day.

2.8 Example 2: Multiple Generators with Energy and Reserves

In this section, we provide a more detailed example with both energy and reserves. The point is to show that the misaligned incentives problem, and its three root causes, are of paramount concern for the resources and capabilities that the system relies upon to manage uncertainties the next operating day. Moreover, this example highlights how the wholesale market, in its current form, may not provide sufficient incentives for the owners of such resources to invest in costly energy supply arrangements *even when* such investments would be a cost-effective means to reduce reliability risk.

Though we develop this next example in the context of energy and operating reserves, the same conclusions would hold similarly if we instead focused on the system's needs for forecast-load imbalances or replacement energy reserves. The situation with operating reserves is more intricate, however, because of how real-time operating reserves are co-optimized with energy during the operating day – and because a failure of these resources to arrange for sufficient energy to operate could create (or magnify) a real-time reserve shortage.

In this example, there are four generators that can provide both energy and operating reserves. To capture many of the factors identified in the prior section, real-time demand is uncertain, and the higher-cost generators do not receive day-ahead market awards. We consider a situation in which one of these higher-cost generators faces the possibility that real-time demand may be high enough for it to operate the next day, but it is more likely the generator will not be needed. Facing this uncertainty, it must decide whether or not to incur the cost of arranging fuel in advance of the operating day.

As with the earlier examples, the interpretation of 'arranging fuel in advance of the operating day' is flexible. It should be viewed as however far in advance as is necessary for the generator in question (a day, a week, a month, a season). In other words, *how far* in advance does not impact the conclusions, or the calculations, of this Example 2.

► **Assumptions.** The capacity and offer price parameters of the four generators are shown in the first panel of Table 2-5. We assume there is a single operating reserve product procured in the real-time market, and each generator's maximum capability to provide that reserve product (due to its ramp rate) is also shown in the table.

Table 2-5. Assumptions for Example 2			
Generator	**Capacity (MW)**	**Offer Price ($/MWh)**	**Reserve Capability (MW)**
Gen 1	100	$25	10
Gen 2	100	$30	20
Gen 3	50	$40	30
Gen 4	50	$90	40
Additional Cost Assumptions for Generator 3			
		Marginal Cost	**Up-Front Cost**
With Advance Fuel Arrangements		$40	$150
No Advance Fuel Arrangements		N/A	N/A
Real-Time Demand Scenarios			
	Low Demand	**Medium Demand**	**High Demand**
Energy Demand (MWh)	170	190	210
Scenario Probability	33%	33%	33%

In the second panel of Table 2-5, we show additional cost assumptions for Generator 3. Its costs depend upon whether or not it arranges fuel in advance of the operating day. If Generator 3 arranges fuel in advance of the operating day, then it must incur an up-front cost of $150. By 'up-front cost,' we mean that if the generator decides to arrange fuel in advance, it would incur the $150 cost regardless of whether or not it operates the next day. And then, in addition, it would incur a marginal cost of $40/MWh to operate – but that marginal cost is incurred only if it does indeed operate.

The additional, market-level assumptions are:

- Day-ahead energy demand is 190 MWh for the hour.

- Real-time energy demand is uncertain: it can be low (170 MWh), medium (190 MWh), or high (210 MWh), each equally likely, as shown in the bottom panel of Table 2-5.
- The real-time reserve requirement is 30 MWh/h.

Last, some simplifications: the time period considered is a single delivery hour; there are no transmission constraints; the generators have no commitment variables (*e.g.,* no startup costs or lead-times); and demand in the day-ahead market matches the ISO's load forecast, so there is no load-balance gap. These simplifications are intended to help focus on the essentials of energy supply incentives, and do not alter the insights of this numerical example.

2.8.1 Market Awards and Clearing Prices

We first evaluate the day-ahead and real-time market outcomes in two cases: Case A, where Generator 3 decides to make advance arrangements for energy supply in advance of the operating day; and Case B, where Generator 3 does not.

We will then examine which decision maximizes Generator 3's expected net revenue, as well as which decision would produce a superior net expected benefit to the system (*i.e.,* minimize the expected value of the system's total production cost).

The **day-ahead** energy market outcome is the same in Case A and in Case B, and is shown in Figure 2-1. The clearing price for energy is $30/MWh, set by Generator 2's offer price. The two lower-cost generators (Generators 1 and 2) receive day-ahead energy market awards, and neither of the two higher-cost generators (Generator 3 and 4) receives a day-ahead energy market award.

Note that there are no day-ahead market awards for reserves in this example, which mirrors the current day-ahead market design in New England. However, the ISO can observe from the day-ahead clearing outcomes that if there are no changes in system conditions, the system would have 80 MWh of operating reserves in real-time spread across three resources (Generators 2, 3 and 4), as shown in the bars shaded green in Figure 2-1.

Next we will turn to **real-time** energy market outcomes.

Case A: Generator 3 arranges fuel. In real-time, demand can take one of three levels. Figures 2-2, 2-3, and 2-4 show the real-time market's energy and reserve co-optimization results for the example's low, medium, and high real-time demand levels, respectively.

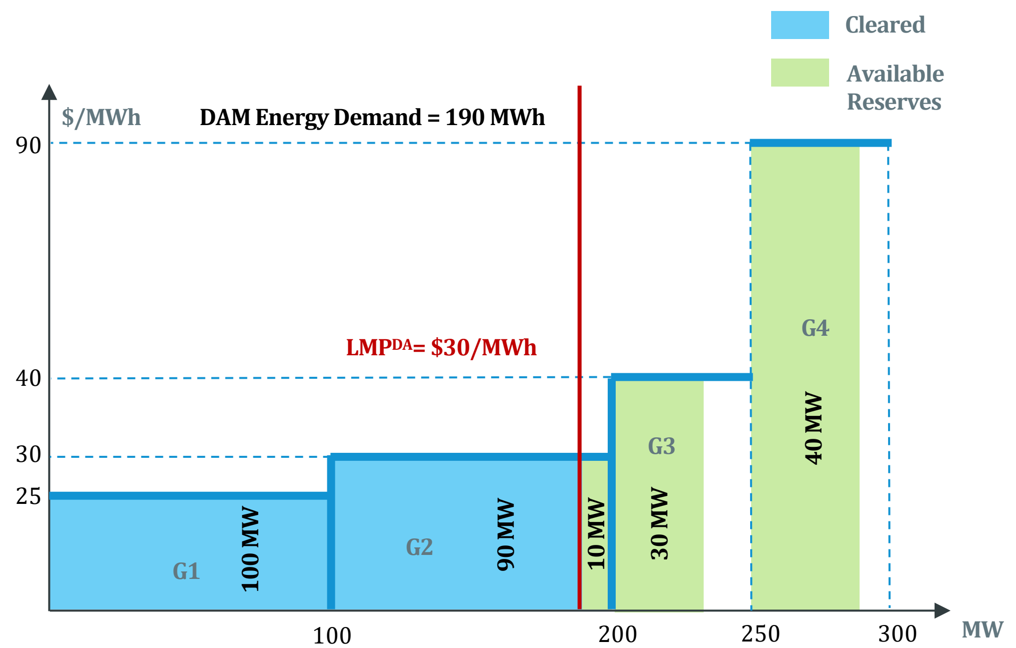

Figure 2-1. Day-ahead market outcomes for Example 2

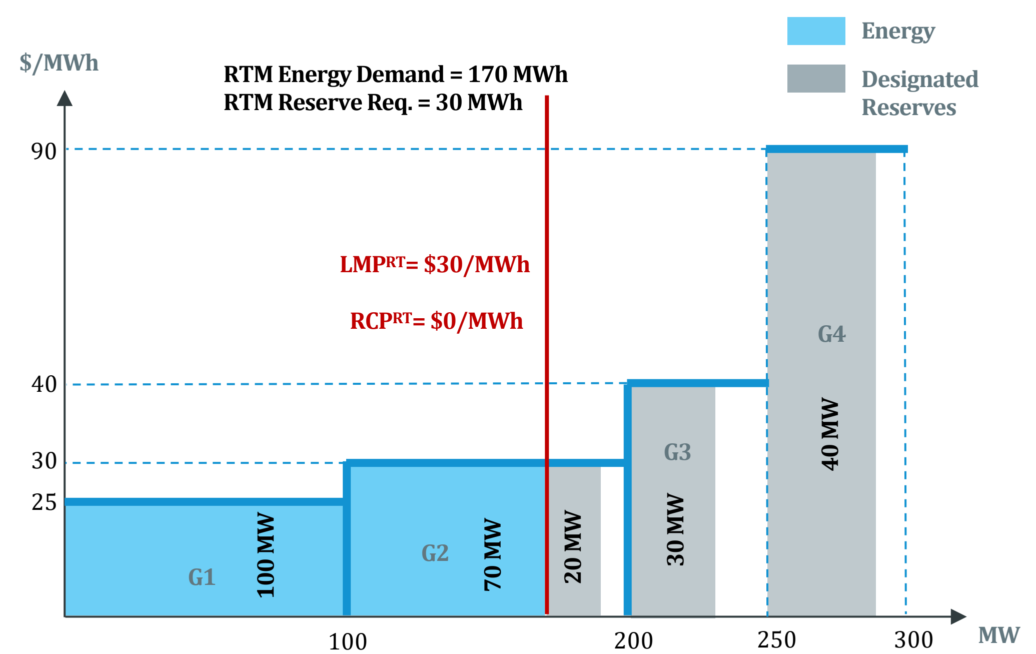

Figure 2-2. Low demand scenario real-time market outcomes for Example 2, Case A

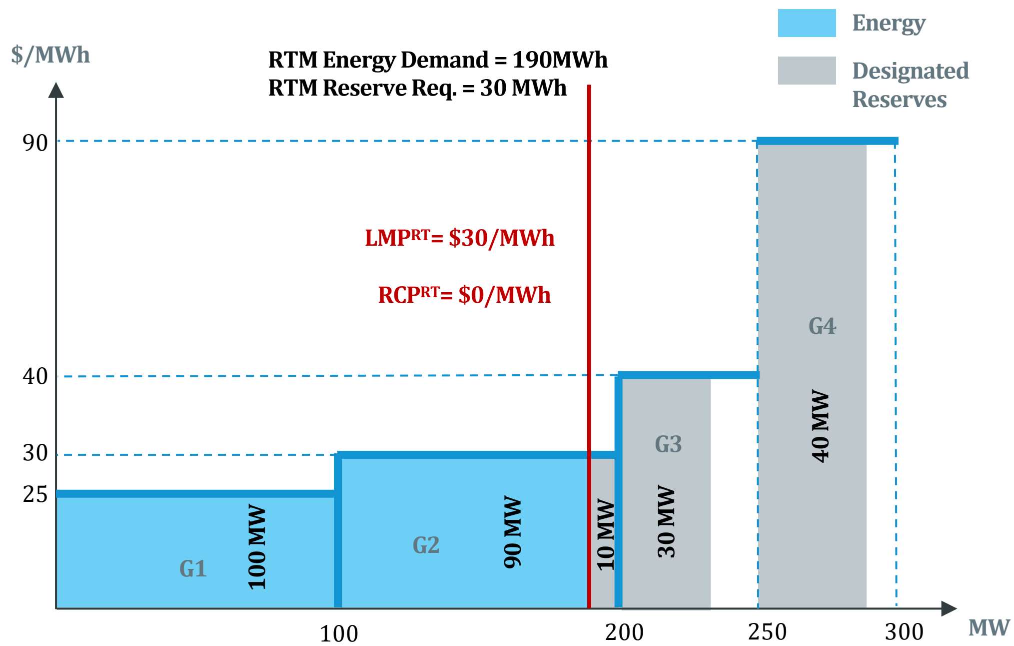

Figure 2-3. Medium demand scenario real-time market outcomes for Example 2, Case A

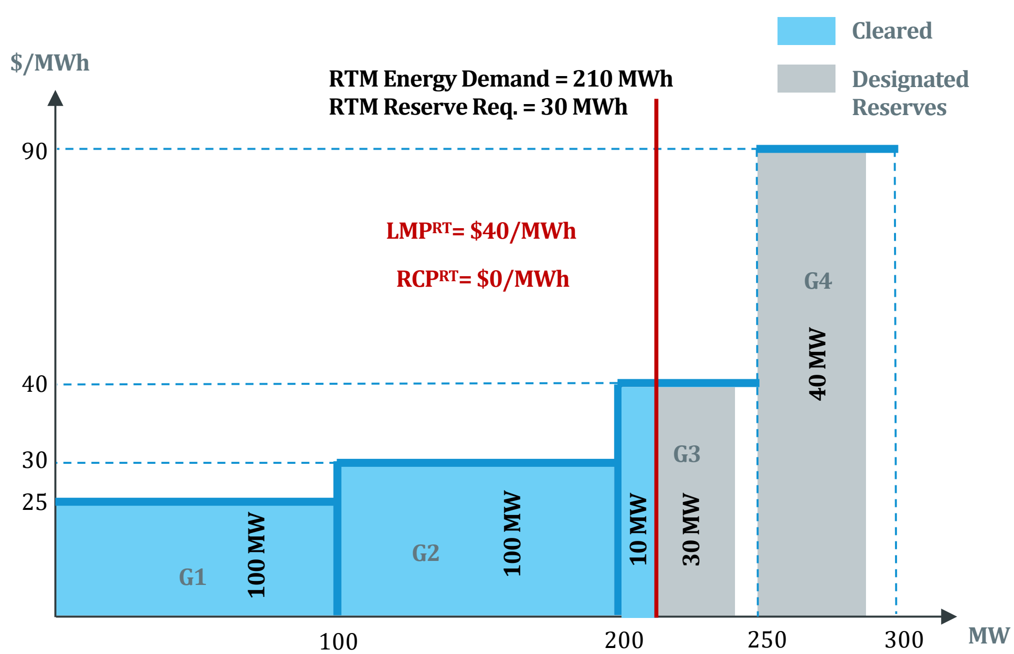

Figure 2-4. High demand scenario real-time market outcomes for Example 2, Case A

These results are summarized in Table 2-6. Figures 2-2 and 2-3, and Row [6] in Table 2-6, show that in the low and medium demand scenarios, Generator 2 remains marginal for energy and the real-time LMP is the same as day-ahead, at $30/MWh. In the high-demand scenario in Figure 2-4, Generator 3 is marginal for energy and sets the real-time LMP at $40/MWh. Row [5] in Table 2-6 indicates that in all three demand scenarios, the total supply of real-time operating reserves exceeds the reserve requirement of 30 MWh, so the real-time price for reserves is zero (as shown in row [6]).

Table 2-6. Market Outcomes for Example 2 , Case A: Generator 3 With Fuel

		Day Ahead		Real-Time Market Outcomes					
		Market Awards		Low Demand		Medium Demand		High Demand	
	Generator	Energy	Reserve	Energy	Reserve	Energy	Reserve	Energy	Reserve
[1]	Gen 1	100	-	100	0	100	0	100	0
[2]	Gen 2	90	-	70	20	90	10	100	0
[3]	Gen 3	0	-	0	30	0	30	10	30
[4]	Gen 4	0	-	0	40	0	40	0	40
[5]	**Totals**	190	-	170	90	190	80	210	70
[6]	**Clearing Price**	$30	-	$30	$0	$30	$0	$40	$0
[7]	Scenario Total Production Cost			$4,600		$5,200		$5,900	
[8]	Demand Probability			33%		33%		33%	
[9]	**Expected Total System Production Cost**					**$5,233**			
[10]	Scenario Market Payments (incl. DAM)			$5,100		$5,700		$6,500	
[11]	**Expected Total Market Payments**					**$5,767**			

For purposes of evaluating cost-effective outcomes, the system's total production costs is shown in rows [7] and [9] of Table 2-6. Row [7] summarizes the system's total production cost in each demand scenario, under the maintained assumption that each resource offers competitively at its marginal cost.[39] Total production costs increase with real-time demand, naturally. Importantly, in these calculations we *exclude* the $150 up-front cost of Generator 3 to arrange fuel in advance of the operating day. We will bring that into the calculations in a subsequent step below.

Row [9] takes the probability-weighted average of the three scenarios' total production costs, which shows that the expected (value of the) system's total production cost is $5,233 (rounding to the nearest dollar). We will compare that outcome to the expected total production cost that prevails if Generator 3 does *not* have advance fuel arrangements in Case B below, which will identify whether

[39] The values in row [7] of Table 2-6 are calculated separately for each demand scenario by multiplying each generator's energy offer price (from Table 2-5) by its real-time market energy outcome (in MWh), and totaling the result. For example, in the high-demand scenario, the calculation is: $25/MWh × 100 MWh for Gen 1, plus $30/MWh x 100 MWh for Gen 2, plus $40 × 10 MW for Gen 3, which totals to a scenario total production cost of $5,900.

the $150 up-front cost of advance fuel arrangements would be cost-effective from the system's standpoint.

Of additional interest are total market settlements. Row [10] provides the total market settlements (including both the day-ahead market, and the deviation-based real-time settlements) for all resources in each demand scenario.[40] Row [11] takes their probability-weighted average to obtain the expected (value of the) total market settlements of $5,767 (again rounding to the nearest dollar). In this example, the expected total market settlements are both the expected total market revenue to the generators, and the expected total payments by buyers. The expected total market settlements are greater than the expected total production costs, both here and generally, because the low-cost generators earn infra-marginal rents – the usual economic reward for superior cost efficiency in a competitive marketplace.

Since there are many numbers involved in a multi-unit market with multiple products (*i.e.,* energy and reserves), we note here the key numbers to keep in mind from Case A:

- The high-demand scenario real-time LMP is **$40/MWh**, and real-time reserve price is **$0/MWh**.
- The expected system total production cost is **$5,233** for the hour, *excluding* Generator 3's $150 up-front cost of arranging fuel (which it will incur in this Case A); and
- The expected total market settlement is **$5,767** for the hour.

Case B: Generator 3 does not arrange fuel. Now consider the market outcomes if Generator 3 does not make arrangements for fuel in advance of the operating day. We will assume the ISO treats each generator as available unless informed otherwise by the generator, consistent with current ISO operational practice. If Generator 3 does not arrange fuel in advance, then we assume that it would seek to acquire fuel on short notice if instructed to operate the next day. In that situation, we assume that Generator 3 is physically unable to obtain fuel (and indicates to the ISO it not available), and the ISO would dispatch the system at least-cost without Generator 3.

In Case B, the real-time market outcomes are unchanged from before in the low and medium demand scenarios; Generator 3 is not instructed to provide energy in real-time in those scenarios. The outcome is different from before in the high-demand scenario, however. In the high-demand scenario in Case B, Generator 3 would not be able to obtain fuel to operate on short notice (by assumption) and would not be available. Therefore, the real-time dispatch would turn to the next higher-cost resource in the supply stack, Generator 4. Figure 2-5 shows the real-time market outcomes in Case B's high-demand scenario.

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[40] The values in row [10] of Table 2-6 are calculated by adding the total day-ahead market awards (190 MW multiplied by the $30 clearing price, or $5,700) to the product of the real-time deviation and the real-time clearing price in each of the three demand scenarios. For example, in the high-demand scenario, positive real-time deviations of 20 MW (10 MW each for Generators 2 and 3) are multiplied by the real-time clearing price of $40, for a total of $800. This amount is added to the $5,700 day-ahead settlement, for a total scenario market payment of $6,500.

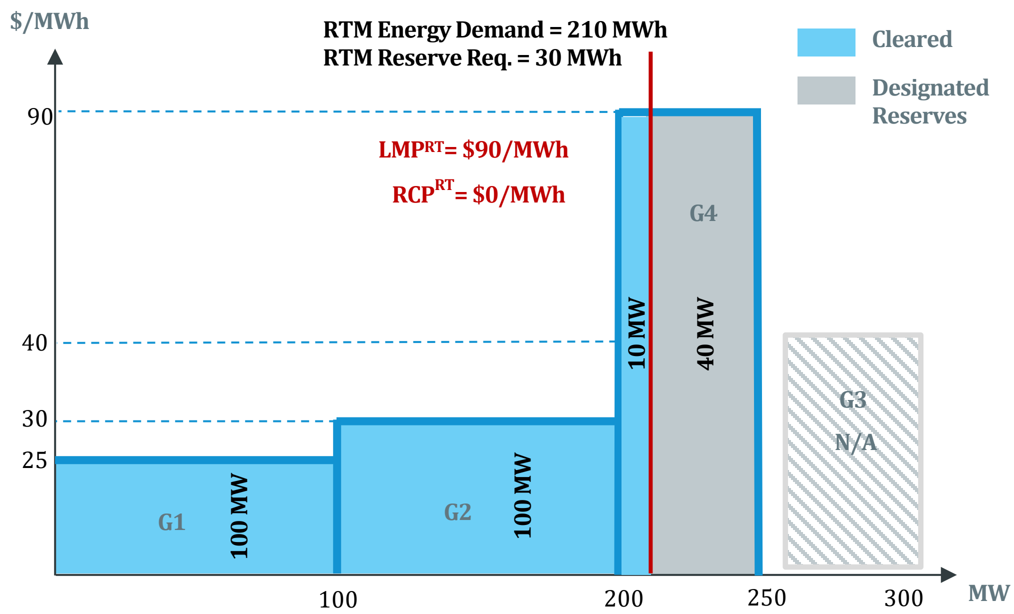

Figure 2-5. High demand scenario real-time market outcomes for Example 2, Case **B**

Table 2-7. Market Outcomes for Example 2 , Case B: Generator 3 Without Fuel

		Day Ahead		Real-Time Market Outcomes					
		Market Awards		Low Demand		Medium Demand		High Demand	
	Generator	Energy	Reserve	Energy	Reserve	Energy	Reserve	Energy	Reserve
[1]	Gen 1	100	-	100	0	100	0	100	0
[2]	Gen 2	90	-	70	20	90	10	100	0
[3]	Gen 3	0	-	0	30	0	30	0	0
[4]	Gen 4	0	-	0	40	0	40	10	40
[5]	**Totals**	190	-	170	90	190	80	210	40
[6]	**Clearing Price**	$30	-	$30	$0	$30	$0	$90	$0
[7]	Scenario Total Production Cost			$4,600		$5,200		$6,400	
[8]	Demand Probability			33%		33%		33%	
[9]	**Expected Total System Production Cos**					**$5,400**			
[10]	DAM)			$5,100		$5,700		$7,500	
[11]	**Expected Total Market Payments**					**$6,100**			

Table 2-7 summarizes the market outcomes in Case B. To facilitate comparisons, we have shaded cells in light orange to highlight the (only) outcomes that differ from the outcomes in Table 2-6 for Case A, in which Generator 3 did arrange fuel in advance.

In the day-ahead market and in the low and medium real-time demand scenarios, Generator 2 remains marginal for energy, and the real-time LMP is the same as day-ahead, at $30/MWh, as shown in row [6]. In the high-demand scenario, Generator 4 now is marginal for energy and sets the real-time LMP at $90/MWh.

Even with Generator 3's unavailability in the high-demand scenario, however, row [5] indicates that the total supply of real-time operating reserves exceeds the reserve requirement of 30 MWh, so the real-time price for reserves is zero. Thus, in this example, Generator 3's unavailability impacts the real-time LMP significantly in the high-demand scenario, but its unavailability does not impact the price of reserves.

Last, for comparison purposes, we have re-calculated in Table 2-7 the system's total production costs and the total market settlements for each demand scenario in Case B, where Generator 3 does not have arrangements for fuel in advance of the operating day. Row [9] shows the expected (value of the) system's total production costs are $5,400. Row [11] shows the expected (value of the) total market settlements is now $6,100.

The key numbers to keep in mind from Case B are:

- The high-demand scenario real-time LMP is **$90/MWh**, and the real-time reserve price is still **$0/MWh**.
- The expected system total production cost is **$5,400** for the hour, when Generator 3 does not incur the $150 up-front cost of arranging fuel (in this Case B); and
- The expected total market settlement is **$6,100** for the hour.

2.8.2 Misaligned Incentives to Arrange Fuel

We now compare the outcomes when Generator 3 has the fuel to operate, versus when it does not. We will see that the energy and reserves markets currently provide inefficiently low incentives for Generator 3 to arrange fuel in advance, even though doing so would be beneficial and cost-effective from the system's standpoint.

► **Cost-effective outcome.** From the standpoint of operating a power system at minimum cost – in terms of the costs incurred by the suppliers to meet demand – the preferred outcome is if Generator 3 arranges fuel in advance. Even though that costs $150 up front and may not be used, it is a cost-effective investment. The system's expected total production cost without it is $5,400 (Case B) and with it is $5,233 (Case A), a difference of $167 – more than enough to cover the $150 up-front cost of the fuel arrangements. Thus, the most efficient, cost-effective outcome for the system is if Generator 3 arranges fuel in advance of the operating day.

This same conclusion applies from the perspective of buyers' total payments, which fall from $6,100 (in Case B) to $5,767 (in Case A, with the advance fuel arrangement). Although changes in buyers' total payments (also called *consumer surplus)* are not a measure of market efficiency, nor a measure of the minimum (most cost-effective) use of society's resources to meet demand, the reduction in total payments is logical: it avoids the scenario where high-cost Generator 4 must be used to meet demand, instead of the lower-cost Generator 3.

Before concluding that all is well, however, we need to bring a bit of the dismal science to bear on the situation. The flip-side of consumers' payments being lower in Case A (when Generator 3 has arranged for fuel) is that total market revenue to the generators is also lower in that case. The question then arises, specifically, whether – given the way the day-ahead and real-time markets currently operate – Generator 3 would find it profitable to invest in arranging fuel in advance of the operating day.

► **The generator's decision.** We now compare Generator 3's expected net revenue in each case, and whether its incentive to arrange fuel in advance is consistent with the efficient, most cost-effective outcome for the system.

The full settlement outcomes for Generator 3 in each case are detailed in Table 2-8. In brief, if Generator 3 does not arrange fuel, it produces zero energy in real-time (in any demand scenario) and its expected net revenue is $0, as shown in the bottom right row of Table 2-8. If it does arrange fuel, Generator 3 produces energy only in the high-demand scenario. In that scenario, it is the marginal unit, so it makes no profit in the real-time market (it sets the real-time LMP at its marginal cost). However, it incurs the $150 up-front cost to acquire fuel. Thus, Generator 3's expected net revenue if it arranges fuel in advance of the operating day is a net financial loss, of $150.

Table 2-8. Generator 3's Expected Net Revenue in Example 2

			Case A: With Advance Fuel			**Case B:** No Advance Fuel		
Generator's Market Settlements		Calculation	Low Dmd	Med Dmd	High Dmd	Low Dmd	Med Dmd	High Dmd
[1]	Day Ahead Energy	*DA LMP * Qe_DA*	$ -	$ -	$ -	$ -	$ -	$ -
[2]	Real-Time Energy Deviation	*RT LMP*(Qe_RT - Qe_DA)*	$ -	$ -	$ 400	$ -	$ -	$ -
[3]	Real Time Reserves	*RT RCP * Qr_RT*	$ -	$ -	$ -	$ -	$ -	$ -
[4]	**Total Settlement**	[1]+[2]+[3]	$ -	$ -	$ 400	$ -	$ -	$ -
Generator's Costs								
[5]	Advance Fuel	*F*	$ (150)	$ (150)	$ (150)	$ -	$ -	$ -
[6]	Variable Cost	*MC*	$ -	$ -	$ (400)	$ -	$ -	N/A
[7]	**Total Cost**	[5]+[6]	$ (150)	$ (150)	$ (550)	$ -	$ -	$ -
Generator's Expected Profit								
[8]	Scenario Net Revenue	[4]+[7]	$ (150)	$ (150)	$ (150)	$ -	$ -	$ -
[9]	Demand Probability	*p* or (1-*p*)	0.333	0.333	0.333	0.333	0.333	0.333
[10]	**Expected Net Revenue**	SumProd [8]*[9]		**($150)**			**$0**	

► **Implications.** The bottom line here is an important one. The energy market, in its current form, may not provide sufficient incentives for resource owners to invest proactively in energy supply arrangements – even when such investments would be cost-effective and yield expected net benefits to the system. In this example, all of the generators are acting perfectly competitively (offering at their marginal cost) throughout. Thus, the right conclusion to draw from Example 2 is *not* that there is a problem with the generators' behavior or their business acumen; rather, the right conclusion to draw from Example 2 is that there is a problem with the current energy market design.

2.8.3 Example 2-R: Reliability Risks

In Example 2, we have not (yet) introduced any reliability considerations. We simply have concluded that from the standpoint of minimizing the system's expected cost, it may be efficient to arrange fuel in advance even when it may not be needed. However, that is not the only potential problem.

We now consider an extension, Example 2-R, where Generator 3's decision to arrange fuel may impact whether or not there is a reserve shortage in real-time. We make the same assumptions as in in Example 2 before, but now 'scale up' two prior assumptions:

- *higher real-time reserve requirement* – the reserve requirement will now be 80 MWh for the hour; and
- *higher up-front cost of arranging fuel* – generator 3's up-front cost to arrange fuel in advance of the operating day is now $1,200.

The first assumption will make a reserve shortage *possible* in the context of Example 2, and produce higher market prices even if the generator arranges fuel in advance of the operating day. The second assumption is related to the first: if a market may produce higher prices even in 'good' cases when the generator has fuel, then the misaligned incentives problem tends to arise when there are higher up-front costs to arrange that fuel. In other words, the second assumption helps better reveal the misalignment problem, given the first assumption.

Broadly, with these two revised assumptions, we have created a more "stressed system" situation in the scenario when real-time demand is high. We will see again that Generator 3 would make the same decision as before to not arrange fuel in advance, based on its own expected net revenue, yet the system would be better off if it did; the outcomes would be more cost-effective and would reduce reliability risk.[41]

[41] To simplify the analysis, in Example 2-R, we will ignore the additional settlements associated with the Pay for Performance market rules that apply during a reserve shortage, which would come into play in the high-demand scenario below. Under the assumptions for Example 2-R, the PFP performance incentives would likely change the generator's decision discussed next (we omit the supporting calculations here). As noted in Section 2.4.1, PFP therefore helps address this reliability risk. However, as illustrated earlier (see Table 2-4), if we revised the present example's probabilities so that there is a sufficiently lower chance of a reserve shortage, then, as illustrated, PFP would not fully resolve the misaligned incentive problem. The reasons are the same as those discussed following Table 2-4 in Section 2.4.2.

Case A: Generator 3 arranges fuel. First consider the market outcomes if Generator 3 does arrange for fuel in advance of the operating day. The day-ahead market outcomes are unchanged from Figure 2-1 previously; the day-ahead LMP is again $30/MWh, set by marginal Generator 2. The total reserve available in the day-ahead market solution is 80 MWh, as before, which (just) satisfies the (revised) expected real-time reserve requirement. (Note that, under the current energy market design, the generators are not compensated for that reserve capability in the day-ahead market).

Table 2-9 summarizes the day-ahead and real-time market outcomes when Generator 3 arranges fuel in advance of the operating day. Row [6] shows that the higher reserve requirement (80 MWh) leads to positive real-time reserve prices in the medium and the high-demand scenarios, and therefore higher production costs and energy prices in those scenarios. Row [9] shows the system's expected total production cost is $5,267 (rounding to the nearest dollar). Row [11] reports the expected total market settlement of $7,967 (rounding to the nearest dollar).

Table 2-9. Market Outcomes for Example 2-R, Case A: Generator 3 With Fuel

		Day Ahead		Real-Time Market Outcomes					
		Market Awards		Low Demand		Medium Demand		High Demand	
	Generator	Energy	Reserve	Energy	Reserve	Energy	Reserve	Energy	Reserve
[1]	Gen 1	100	-	100	0	100	0	100	0
[2]	Gen 2	90	-	70	20	90	10	90	10
[3]	Gen 3	0	-	0	30	0	30	20	30
[4]	Gen 4	0	-	0	40	0	40	0	40
[5]	**Totals**	190	-	170	90	190	80	210	80
[6]	**Clearing Price**	$30	-	$30	$0	$40	$10	$90	$60
[7]	Scenario Total Production Cost			$4,600		$5,200		$6,000	
[8]	Demand Probability			33%		33%		33%	
[9]	**Expected Total System Production Cost**					**$5,267**			
[10]	Scenario Market Payments (incl. DAM)			$5,100		$6,500		$12,300	
[11]	**Expected Total Market Payments**					**$7,967**			

Case B: Generator 3 does not arrange fuel. Now consider the market outcomes if Generator 3 does not make arrangements for fuel in advance of the operating day. In this situation, the real-time market outcomes are unchanged in the low and medium demand scenarios. The high-demand scenario is different from Case A, however. In this scenario, Generator 3 would not be able to obtain fuel to operate (by assumption) and would be unavailable. Therefore, the real-time dispatch would instead use the next higher-price resource, Generator 4. Figure 2-6 shows the real-time market outcomes in this high-demand scenario. Here, the remaining capability on the system (of

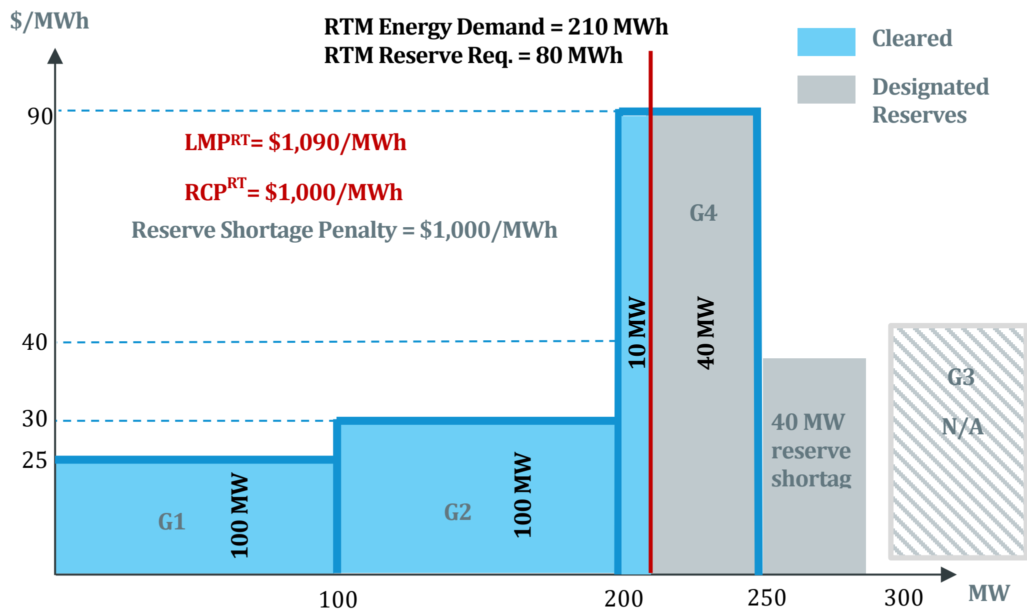

Figure 2-6. High demand scenario real-time market outcomes for Example 2, Case **B**

Generator 1, 2, and 4) is not enough to cover the total energy and reserve requirement, and there is a reserve shortage of 40 MWh.

Table 2-10 below summarizes the day-ahead and real-time market outcomes when Generator 3 does not arrange fuel in advance of the operating day. The outcomes that differ from Case A in Table 2-9, when Generator 3 has arranged fuel, are in the cells shaded in light orange in Table 2-10. We assume here that the reserve clearing price is $1,000 per MWh in the high-demand scenario with the reserve shortage. Row [9] shows the system's expected total production cost is $18,733 (rounding to the nearest dollar), which incorporates the cost of the reserve shortage at its market price signal of $1,000. Row [11] shows the expected total market settlement of $26,367 (rounding to the nearest dollar).

Table 2-10. Market Outcomes for Example 2-R, Case B: Generator 3 Without Fuel

		Day Ahead		Real-Time Market Outcomes					
		Market Awards		Low Demand		Medium Demand		High Demand	
	Generator	Energy	Reserve	Energy	Reserve	Energy	Reserve	Energy	Reserve
[1]	Gen 1	100	-	100	0	100	0	100	0
[2]	Gen 2	90	-	70	20	90	10	100	0
[3]	Gen 3	0	-	0	30	0	30	0	0
[4]	Gen 4	0	-	0	40	0	40	10	40
[5]	**Totals**	190	-	170	90	190	80	210	40
[6]	**Clearing Price**	$30	-	$30	$0	$40	$10	$1,090	$1,000
[7]	Scenario Total Production Cost			$4,600		$5,200		$46,400	
[8]	Demand Probability			33%		33%		33%	
[9]	**Expected Total System Production Cost**					**$18,733**			
[10]	Scenario Market Payments (incl. DAM)			$5,100		$6,500		$67,500	
[11]	**Expected Total Market Payments**					**$26,367**			

► **Cost-effective outcome from society's perspective.** In Example 2-R, when Generator 3 has not arranged in advance for fuel to operate, the system's expected total production cost, including the reserve shortage of 40 MWh at its shortage price, is $18,733. When Generator 3 does arrange in advance for fuel, which prevent the reserve shortage, the system's expected total production cost is $5,267. This is a vast difference that is more than enough to cover the $1,200 up-front cost of the fuel arrangements. Thus, the most efficient outcome is if Generator 3 arranges fuel in advance of the operating day.

► **The generator's decision.** Now compare Generator 3's expected net revenue in each case, and whether its incentive to arrange fuel in advance is consistent with the efficient, most cost-effective outcome for the system.

The full settlement outcomes for Generator 3 are detailed below in Table 2-11. In brief, if Generator 3 does not arrange fuel, its expected net revenue is $100, as shown in the bottom-right cell in row [10] of Table 2-11. If it does arrange fuel, it is once again in the red, incurring a $167 net loss, as shown in the bottom-left cell of row [10].

The point here is again simple. The current energy and real-time-only reserve market design does not provide proper incentives for Generator 3 to incur the high up-front $1,200 cost of arranging energy supplies in advance, but it would both be cost-effective from society's standpoint and reduce the system's reliability risk if it did.

Table 2-11. Generator 3's Expected Net Revenue for Example 2-R, Under Status Quo/Existing Rules								
			Case A: Advance Fuel			**Case B:** No Advance Fuel		
Generator's Market Settlements		Calculation	Low Dmd	Med Dmd	High Dmd	Low Dmd	Med Dmd	High Dmd
[1]	Day Ahead Energy	*DA LMP * Qe_DA*	$ -	$ -	$ -	$ -	$ -	$ -
[2]	Real-Time Energy Deviation	*RT LMP*(Qe_RT - Qe_DA)*	$ -	$ -	$ 1,800	$ -	$ -	$ -
[3]	Real-Time Reserves	*RT RCP * Qr_RT*	$ -	$ 300	$ 1,800	$ -	$ 300	$ -
[4]	**Total Settlement**	[1]+[2]+[3]	$ -	$ 300	$ 3,600	$ -	$ 300	$ -
Generator's Costs								
[5]	Advance Fuel	*F*	$ (1,200)	$ (1,200)	$ (1,200)	$ -	$ -	$ -
[6]	Variable Cost	*MC*	$ -	$ -	$ (800)	$ -	$ -	NA
[7]	**Total Cost**	[5]+[6]	$ (1,200)	$ (1,200)	$ (2,000)	$ -	$ -	$ -
Generator's Expected Profit								
[8]	Scenario Net Revenue	[4]+[7]	$ (1,200)	$ (900)	$ 1,600	$ -	$ 300	$ -
[9]	Demand Probability	*p* or (1-*p*)	0.333	0.333	0.333	0.333	0.333	0.333
[10]	**Expected Net Revenue**	SumProd [8]*[9]		**($167)**			**$100**	

2.9 Implications and Summary

We now consider some of the broader insights illustrated in Example 2, and connect those insights back to the energy gaps, and essential reliability services used to fill them, as discussed in Sections 2.6 and 2.7 above.

First, Example 2 illustrates a market inefficiency with the current energy market design. Generator 3's market incentives are to *not* incur the costs of arranging fuel in advance of the operating day, but society would be better off if it did. In plain terms, the current market design does not incent cost-effective outcomes.

Revisiting the three root causes of this market inefficiency discussed in Section 2.5 above as they apply to Generator 3 in Example 2:

Root Cause 1: **Generator 3 faces significant production uncertainty** – after all, there is only a 33% chance it will be in demand the next day.

Root Cause 2: **Generator 3 faces significant, irrevocable up-front costs** (of $150), relative to its expected gross margin (which, in this example, is zero); that leaves it with no infra-marginal revenue to cover the up-front cost.

Root Cause 3: **Generator 3's decision to invest in fuel arrangements – or not – is material.** It impacts the resulting market price for real-time energy (with some probability). Making the advance fuel arrangements would enable it to produce in the high-demand scenario, rather than forcing the system to use the next higher-cost resource in the supply stack (Generator 4, and, in the more stressed case, with a reserve shortage).

Thus, in incurring the private cost of investing in energy supply arrangements in advance of the operating day, the generator cannot recoup that investment in the current energy market design. However, that same investment would produce more than enough savings in expected total system production costs to make it efficient and cost-effective for the system overall. This difference between the private benefits of the investment (to Generator 3) and the expected total production cost savings (to society) results in the misaligned incentive problem, and higher expected costs to society as a result.

Second, Example 2 is structured to illustrate why the three root causes are of potential concern for the resources that the system relies upon to provide the essential reliability services itemized in Section 2.6.1 above. Generator 3 is extra-marginal in the day-ahead market and does not have a day-ahead award, which is characteristic of the resources the ISO relies up for those three operational capabilities each day. Generator 3 has slim energy market gross margins (infra-marginal revenue) on the occasions when it is dispatched for energy, providing little revenue with which to recoup – and therefore little financial incentive to incur – the up-front cost of arranging fuel in advance. And yet, during stressed system's conditions, Generator 3's operation is essential to prevent the system from needing to turn to much higher-cost generators to meet demand (and, in extreme cases, to avoid a reserve shortage).

Third, Example 2 also shows why these root causes do not apply (or do not apply to nearly the same extent) to the system's lower cost, more efficient resources that clear in the day-ahead market. Imagine, for example, that the low-cost Generator 1 and higher-cost Generator 3 in Example 2 both faced a similar $150 cost of arranging fuel in advance of the operating day. The efficient outcome would also be for Generator 1 to incur that cost. Would it be financially incented to do so, under the current energy market? *Yes*. In Example 2, Generator 1 makes a $500 gross margin *in the day-ahead market*, easily enough to motivate – and recoup the cost of – a $150 up-front cost of arranging its fuel in advance of the operating day. This logic, though simplified in the context of Example 2, mirrors the real-world economic rationale for why the ISO has not observed significant problems with gas-fired resources that clear *in the day-ahead market* failing to have sufficient fuel to meet their day-ahead energy market awards.

Last, from a reliability perspective, Example 2 illustrates that the system is potentially relying upon resources for reserves that may not be able to obtain fuel if dispatched for energy during the operating day. In Example 2, Generator 3 does not *expect* to operate and it *plans* to acquire fuel if dispatched (when it does not arrange fuel in advance, as illustrated in Case B in Section 2.8.1). From Generator's 3 perspective, it is not financially prudent to incur the costs of arranging fuel in advance, knowing that the arrangement most likely will not be used. However, as a result, based on the day-ahead market outcome in Example 2-R (Figure 2-5), the ISO would anticipate having 80 MWh of reserves when preparing the next-day operating plan – even though Generator 3 may not be able to operate.

In sum, as Example 2 illustrates, for the resources to which the three root causes above reasonably apply, it is logical to be concerned that the region may find these resources do not have sufficient energy supply arrangements if called during the operating day. And these conclusions help to explain why the region's existing wholesale market construct requires new solutions to address the reliability concerns detailed in the accompanying Brandien Testimony.

Our broad conclusion from these observations is that those resource owners are acting rationally given the operating uncertainties and difficult economic circumstances they face. The problem lies in the existing energy market design. The current energy and ancillary services markets have not changed, in their fundamental product suite, for about fifteen years; and they were not designed in anticipation that the three root causes identified above would present a material issue for a significant portion of the generation fleet.

Crucially, the misaligned incentives problem that these three root causes precipitate is not likely to solve itself. Rather, we expect it is apt to become worse, given the evolving resource mix in New England's power system and the greater operational uncertainties associated with ever more just-in-time energy sources. Therefore, and consistent with the Commission's direction, the ISO concludes that it is important "to develop longer-term market solutions" that will better align these incentives.[42] With the appropriate market design changes, generators should find it in their private interest to invest in additional energy supply arrangements whenever those arrangements would be a cost-effective means to reduce the system's reliability risk.

[42] July 2, 2018 Order at P 54.

3. Objectives and Design Principles

To understand the longer-term market solutions being implemented to address these problems, it is useful to proceed from a concise set of design objectives and principles. Specifically, the ISO's approach to developing these solutions reflects the following objectives and design principles.

3.1 Three Central Objectives

In concise terms, the ISO identified three central objectives that define the desired outcomes for both near-term and longer-term regional energy security improvements. These are:

1. **Risk Reduction.** Reduce the heightened risk of unserved electricity demand when the region's just-in-time generation technologies are limited by fuel infrastructure constraints, adverse weather conditions, or both.

2. **Cost Effectiveness**. Improve the region's competitive energy markets to achieve this risk reduction cost-effectively.

3. **Innovation.** Provide clear incentives for all capable resources, including new technologies, that can reduce this risk effectively over the long-term.

We anticipate that this third objective will become increasingly important over time, as the region's older (non-gas-fired) generation facilities reach the end of their service lives and as the New England states work steadily to advance their de-carbonization goals.

Based on the analysis of problems and root causes above, the solution presented here achieves these broad objectives through three tangible means. First, it strengthens generation owners' financial incentives to undertake more robust energy supply arrangements, when cost-effective. That requires innovative solutions, and directly addresses the misaligned incentives problem.

Second, it does not prescribe what form those supply arrangements may take. As technology evolves, suppliers will possess the best information as to what means of bolstering their energy supply arrangements will prove most cost-effective. We view that approach as consistent with all three objectives above.

Third, the solution presented here will better reward resource flexibility that helps manage, and prepare for, energy supply uncertainties during the operating day. These uncertainties may well become more challenging over time, given the increasingly just-in-time nature of New England's power system. Making these improvements through competitive, transparent market mechanisms that reward all capable resources – regardless of technology – serves all three central objectives above.

3.2 Design Principles

In developing market improvements to achieve these three objectives, the ISO focused on four core design principles. These design principles usefully circumscribe the means through which the foregoing objectives will be achieved.

Design Principle 1: **Product definitions should be specific, simple, and uniform.** The same well-defined product or service should be rewarded, regardless of the technology used to deliver it. Simplicity in product definitions enhances competition and participants' understanding.

Design Principle 2: **Transparently price the desired service.** A resource providing an essential reliability service (for instance, a call on its energy on short notice) should be compensated at a transparent price for that service.

Design Principle 3: **Reward outputs; do not specify inputs.** Compensating for obligations to deliver the output that a reliable system requires creates a level playing field for competitors that deliver energy reliably. This rewards suppliers that reduce risk in the most cost-effective ways, and fosters innovation in new solution technologies.

Design Principle 4: **Compensate all resources that provide the desired service similarly.** Paying similar rates for similar service is non-discriminatory by fuel-type or technology, and sends the broadest-possible market signal for the desired attribute.

These are familiar, not novel, principles for economically-sound market design. They help to ensure that the tangible solutions developed will be robust and will continue to function properly as the markets' fundamentals change over time.

Indeed, as the economic environment evolves, a good solution will not need to be continually revisited, and its market rules will not need to be successively perturbed. Achieving that requires a solution that employs sound economic principles, integrates well with the existing wholesale market structure (both from a technical standpoint for the ISO, and from a commercial standpoint for participants), and minimizes administrative rules, restrictions, and parameters whose appropriateness may not persist as the system evolves.

Ultimately, the market design solution we discuss next should help to allay the tensions that have emerged over New England's energy security challenges in recent years, and provide sustainable benefits to the region's competitive wholesale marketplace by adhering to these familiar market design principles.

4. Solution Concepts: Energy Options

In this section, we discuss the conceptual logic of a long-term market solution to the problems detailed in Section 2, and that achieve the objectives in Section 3. The overall design approach builds upon familiar energy and ancillary service concepts used in the wholesale electricity markets. Broadly, the Energy Security Improvements expand the existing suite of energy and ancillary service products in the ISO-administered markets, in order to address – reliably and cost-effectively – the uncertainties and supply limitations inherent to a power system evermore reliant on just-in-time energy technologies.

Specifically, the Energy Security Improvements introduce a new set of products in the day-ahead markets that help to better address the region's fuel security concerns, while being closely aligned with the power system's existing reliability requirements. These new products take the form of several new ancillary services in the day-ahead market. Importantly, the settlement design for these ancillary services is both intuitively natural and, on close inspection, provides an economically sound solution to the misaligned incentives problem detailed above in Section 2.

At a high-level, the design provides the ISO with the option to "call" on the energy of an ancillary service seller during the operating day, above and beyond its day-ahead energy schedule (whether or not it has one), in amounts and over timeframes that are carefully designed to match the specific essential reliability needs detailed in Section 2.6. Moreover, the design will also tend to increase the total compensation for energy sold in the day ahead market as well, further increasing the incentives for all suppliers to ensure they have sufficient energy supply arrangements to operate as scheduled in real-time.

In this section, we address the rationale, properties, and conceptual logic for a call option on resources' energy during the operating day to satisfy the requirements for a set of new day-ahead ancillary services. We provide simple illustrative examples in this Section 4, and more detailed design examples and analysis in later sections of the paper.

4.1 Key Components and Rationales

Developing new products in the wholesale electricity markets requires careful attention to details such as resources' offer formats, requisite capabilities, settlement processes, and so forth. Here, we provide a higher-level overview of the key concepts and properties of the new day-ahead ancillary services.

Our immediate purpose is to provide conceptual clarity on the design, rationale, and the role of energy options in ancillary services' settlements. Later, in Sections 6 and 7, we will provide additional detail on product-specific pricing, clearing, and other design elements, as well the associated new Tariff provisions.

► **Product definitions.** At a high level, a day-ahead seller of the new ancillary services introduced by the Energy Security Improvements (each of which will be described specifically below) is providing the ISO with a "call" on its resource's electric energy (*i.e.,* its output) during the operating day. A generator that provides these services would have both a day-ahead and a real-time settlement for the hours for which it acquires a day-ahead ancillary services obligation. Different time-related parameters (*e.g.,* generator ramp or startup times) are relevant to the different ancillary service products, but apply similarly to all sellers of the same product.

This approach to the product definition is intended to be specific, simple, and uniform (Design Principle 1, as discussed in Section 3.2) and it (rewards the output capabilities the system requires, not suppliers' inputs (Design Principle 3). Moreover, it will help to achieve all three of the central objectives described in Section 3.1.

► **Pricing and compensation.** The market clearing process for the expanded day-ahead energy and ancillary services (E&AS) market will compensate both energy and ancillary services at uniform, transparent, product-specific market prices. This serves to satisfy Design Principles 2 (price transparency) and 4 (non-discrimination).

The clearing prices of these day-ahead ancillary services will vary over time (*i.e.,* each hour), as their supply and demand dictate. In this way, the pricing serves to reward the resources that are the most cost-effective suppliers of each product for any given hour. Importantly, the clearing prices of each day-ahead product account for the *inter-product opportunity cost* that can arise if a seller is awarded one particular day-ahead product instead of a different day-ahead product for the same delivery hours (more about which presently).

► **Participation.** Offers to provide these ancillary services are voluntary, consistent with the mission of the ISO "to provide market rules that . . . promote a market based on voluntary participation … [for] any required service."[43] This allows resource owners to continue to sell just energy (and not to sell day-ahead ancillary services), if they expect that doing so is their most profitable opportunity in the ISO's revised day-ahead energy and ancillary services markets. The ISO's regulation ancillary service market, for example, operates on a similar premise.

At the opposite end of the participation spectrum, a resource owner that wishes to submit day-ahead offers to sell energy and one or more of the new day-ahead ancillary services would be free to do so. If submitted, however, an energy option offer must be accompanied by an energy supply offer from the same physical resource, to ensure the resource's physical characteristics and offer prices can be appropriately accounted for in the market clearing process (more about which below).

► **One offer, multiple products.** Under the new design, resources will submit a single energy option offer. That offer may be cleared, in the day-ahead market, for energy imbalance reserve, generation contingency reserve, or replacement energy reserve – the three new day-ahead ancillary services, discussed in detail below. That is, a market participant does not submit separate option offers for each type of ancillary service; it submits a single offer, and the market clearing process determines how that offer (and the physical capabilities of the associated resource) can most cost-effectively serve the system's day-ahead ancillary service requirements. This feature of the clearing

[43] Tariff Section I.1.3(c).

process is important in order to avoid "double-award" problems (*i.e.,* this avoids awarding multiple obligations to the same MW of a seller's resource's capability in the same delivery hour).

This 'one offer, multiple products' system simplifies the overall design. Moreover, it is economically sensible because each product is identically settled, as an energy call option, based on the real-time energy price (discussed further in Section 4.3 below). Equally importantly, using this 'one offer, multiple products' design means that every offer can be substituted, by the clearing engine, to meet any of the new day-ahead ancillary service requirements (up to the physical limits of the associated resource). That substitutability enhances the overall competitiveness of the day-ahead ancillary service market, since each offer effectively competes (up to the limits of the resource's physical capability) with the 'full pool' of all other energy option offers.

► **Physical capabilities.** Day-ahead ancillary service awards are associated with specific physical resources, and the market clearing process is expressly based on resources' physical operating characteristics. For example, a resource's day-ahead 10-minute ancillary service product award depends upon (and is limited by) the resource's 10-minute ramping capability (or, if scheduled to be offline for the hour, its 10-minute startup capability). More generally, resources' time-related physical capabilities (ramp rates and startup times) will determine, in part, their day-ahead market awards for these time-differentiated ancillary service products.

Note that a resource's ramping capability and scheduled on- or off-line status depend on its energy award for the hour. For example, a resource that is economically scheduled to supply energy at its maximum physical energy production level in the day-ahead market has no additional production capability with which to provide reserves. The day-ahead market clearing process, which will be jointly performed for energy and all ancillary services simultaneously, accounts for these physical resource capabilities and limits.

► **Day-ahead co-optimized clearing.** To ensure cost-effectiveness, the award of all day-ahead ancillary services will be co-optimized (*i.e.*, simultaneously cleared) with participants' day-ahead energy supply and demand awards. That will enable the market-clearing process to determine the most cost-effective assignment of resource offers to awards for all products.

That co-optimization process ensures, by design, that the clearing price for each ancillary service product will incorporate the (marginal) suppliers' opportunity costs of not receiving an award for a different day-ahead product. It also means that the day-ahead prices for energy will depend, in general, upon the clearing prices for the ancillary services as well. In that respect, the day-ahead market will share many of the pricing properties presently found in the ISO's co-optimized real-time energy and operating reserve markets.

With these key concepts in hand, we next introduce the specific new ancillary service products.

4.2 New Ancillary Service Products in the Day-Ahead Markets

Section 2.6 described three essential reliability services that the system relies upon, above and beyond resources' day-ahead energy market awards, to prepare for and to help manage the potential energy 'gaps' that can arise in the next-day operating plan. The Energy Security

Improvements formalize these three categories of operational requirements into specific ancillary service capabilities, and allow resources to compete to provide those capabilities in an expanded day-ahead energy and ancillary services market. Broadly, the purpose is to improve today's market construct so that the future resource mix will undertake additional energy supply arrangements, and pursue addition of new technologies, that will ensure these essential capabilities remain available to the power system each operating day.

In concrete terms, these three categories of day-ahead ancillary services are:

A. **Energy Imbalance Reserves.** Energy imbalance reserves are a new product to be procured in the day-ahead E&AS market. It serves a simple purpose: to provide the ISO with sufficient energy "on call" to cover the forecast load imbalance – that is, the 'gap' – when the total energy cleared in the day-ahead market from physical supply resources (*e.g.,* generation and net imports) is less than the ISO's forecast energy demand, in one or more hours, for the next (operating) day.

   Energy imbalance reserves are important because the ISO's forecast energy demand for each hour of the next operating day frequently (but not always) exceeds the total bid-in energy demand, and therefore total cleared supply, in the day-ahead energy market. Under applicable reliability standards, the ISO's operating plan for the next day is intended to ensure there is sufficient energy to cover the forecast load each hour – not simply the level of demand cleared in the day-ahead energy market.[44]

   Importantly, energy imbalance reserve is in addition to, and distinct from, the capabilities necessary to ensure that the system is prepared to handle supply-loss contingencies and replacement energy – the new ancillary services that address those needs are discussed next.

B. **Generation Contingency Reserves.** Generation contingency reserves refers to three resource capabilities that the ISO currently designates and maintains in the real-time market for operating reserves. These are ten-minute spinning reserves (TMSR), ten-minute non-spinning reserves (TMNSR), and thirty-minute operating reserves (TMOR). In simpler terms, all three are forms of fast-start or fast-ramping generation capability.

   The ISO relies upon these capabilities to ensure the system is prepared to promptly restore power balance (consistent with the timeframes established in applicable reliability standards) in response to a sudden, unanticipated power supply loss during the operating day.[45] Under the Energy Security Improvements, the ISO will procure, and compensate for, these same three fast-start or fast-ramping capabilities in the day-ahead E&AS market.

[44] *See* Brandien testimony at pp. 18-19.

[45] *See* Brandien Testimony at pp. 7-8.

C. Replacement Energy Reserves. Replacement energy reserves are new products to be procured in the day-ahead E&AS market. At a high-level, these reserves will provide the ISO with the option to "call" on the energy of an replacement energy reserve resource, above and beyond its day-ahead energy market award (whether or not it has one), over specific timeframes of more than an hour (*e.g*., energy to be provided within 90 minutes, or within four hours).

The ISO relies on replacement energy reserve capabilities to provide the energy needed to replace a day-ahead cleared resource that is unexpectedly unable to operate for an extended (multi-hour to multi-day) duration. In practice, the ISO can rely on the generation contingency reserve resources (those described in category B in Section 2.6.1) for energy for only a limited amount of time after a contingency (*e.g.,* a few hours or less – a duration that may vary with resource availability, demand, and other operating day conditions). After that point, the replacement energy to cover a contingency's balance-of-day energy gap must come from the dispatch and commitment of other resources operating above and beyond their day-ahead awards.

Under the Energy Security Improvements, the ISO will procure two types of replacement energy reserves in the day-ahead E&AS market: ninety-minute replacement energy reserve (RER90) and four-hour (240 minutes) replacement energy reserves (RER240). These two products are designed to align closely with the specific timeframes prescribed in existing reliability standards for the restoration of Generation Contingency Reserves – which, in turn, requires sufficient replacement energy, on those specific same timeframes, to restore the system's generation contingency reserve to reserve (non-energy-producing) status.[46]

For the resources that the ISO relies upon for these three essential reliability services, the design of these day-ahead products directly addresses the misaligned incentives problem explored previously in Section 2. That is, the new design seeks to better align incentives so that generators will choose to invest in additional energy supply arrangements when those arrangements are a cost-effective means to reduce the system's reliability risk.

Specifically, Section 2 identified three inter-related problems that help explain the region's energy security risks and the need for market design improvements: misaligned incentives (Problem 1), operational uncertainties (Problem 2), and insufficient day-ahead scheduling (Problem 3). The first of these new day-ahead ancillary services, energy imbalance reserves, addresses Problems 1 and 3. The latter two of these new services, generation contingency reserves and replacement energy reserves, help the system to manage uncertainties that can arise during the operating day by addressing both Problems 1 and 2. Taken together, these day-ahead market ancillary services will provide, and compensate for, the flexibility of robust, reliable energy supplies 'on demand' to manage uncertainties each operating day.

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[46] *See* Brandien testimony at pp. 11-17.

Other notable features of the new day-ahead ancillary services include:

► **The day-ahead load forecast.** To procure only the minimum energy imbalance reserve necessary each day, the ISO will incorporate the system's forecast load into the day-ahead E&AS market clearing process. Conceptually, the quantity of energy imbalance reserve procured for each hour of the next operating day will be (just) enough to fill the 'gap' (when positive) between the day-ahead forecast load for the hour and the amount of physical energy supply that clears in the day-ahead market.

In New England, the day-ahead market presently clears (nearly) always on the price-sensitive portion of market participants' aggregate energy demand curve. Under the new day-ahead E&AS market, when the price of energy is low, the market will tend to clear more energy and the forecast load-imbalance 'gap' will tend to be small (or zero); in that case, the day-ahead E&AS market will procure relatively little (or zero) energy imbalance reserve. At other times, when the market clears less energy, more energy imbalance reserve will be procured in order to cover the system's next-day load forecast. In this way, the specific balance of energy imbalance reserve and physical energy supply cleared in the co-optimized day-ahead market will be jointly (*i.e.,* simultaneously) determined, in conjunction with all other bids, offers, and ancillary service requirements.

From an economic perspective, incorporating the load forecast into the day-ahead E&AS market effectively creates another demand "curve" for energy – that is, *in addition to* the demand for energy comprised of market participants' aggregate day-ahead bids to buy energy. The additional source of demand will, in general, increase the compensation to *all* supply resources scheduled for energy in the day-ahead market. This additional compensation will be transparently and uniformly priced, as a new component of the day-ahead market's compensation to supply resources scheduled to provide energy. We discuss this important component of our co-optimized day-ahead market design in detail in Section 6.

► **Other Ancillary Service Demand Quantities.** The demand quantities to be cleared for each new day-ahead ancillary service product reflect the requirements of a reliable next-day operating plan, as summarized earlier in Section 2.6.3. Those demand quantities are based on existing reliability standards.[47]

In practice, the MWh of ancillary services necessary to satisfy those next-day operating requirements are inherently dynamic, varying day-by-day and hour-by-hour based (in large part) on the forecast demand profile, the generation cleared for energy in the day-ahead market, and the system's largest energy-source losses (*i.e.,* contingencies) during the course of the operating day. We provide additional detail on these demand quantities in Sections 6.1.2 and 7.3.

► **Product substitution.** Conceptually speaking, there are many possible assignments of resources' capabilities to the system's day-ahead ancillary service products. For instance, a generator that is capable of providing generation contingency reserve, but that is not cleared as generation contingency reserve (economically) for a particular delivery hour, might instead be economically

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[47] *See* Brandien Testimony at pp. 26-30.

cleared to supply replacement energy reserve. The reverse is not necessarily true (*e.g.,* depending on a resource's startup-time or ramp-rates, a resource that can provide replacement energy reserve may not be capable of supplying generation contingency reserves).

At a different level, the capabilities procured for generation contingency reserve can, for a period of time after a contingency, potentially serve to meet some of the system's replacement energy reserve requirements during the same hours. The details of these relationships, which can be quite technical, are formally known as the *product substitution* structure. These relationships impact both the efficient pricing and clearing of ancillary services, and are addressed in detail in Section 7.2.

► **Real-time remains least-cost dispatch.** Because suppliers in the New England markets have the ability to update their energy supply offer prices ("re-offer") when their costs change during the operating day, the least-cost solution to the system's real-time energy and reserve requirements during the operating day may be different than the day-ahead solution. Thus, the dispatch of energy and the designation of real-time reserves, and the economic evaluation of any additional commitments (whether fast-start or otherwise) after the day-ahead market, will continue to be performed based on the resource offers in effect in real-time. The real-time dispatch of the system would continue to perform co-optimization of energy and operating reserves, as is the case today.

► **Energy options, not daily forward reserves.** All of the new day-ahead ancillary services – energy imbalance reserve, generation contingency reserve, and replacement energy reserve – will be settled as call options on real-time energy. This means that the day-ahead market will procure options on real-time energy from physical resources; not ancillary services that settle against resources' anticipated real-time reserve designations.

To clarify that point, note that the ISO also maintains real-time contingency reserve products (day-ahead TMSR, TMNSR, and TMOR) in the real-time market (namely, real-time operating reserve designations of resources' unloaded capability that can ramp up, or startup from an offline state, to deliver additional energy within 10 or 30 minutes). The day-ahead generation contingency reserve product awards will not settle against the real-time prices for these real-time reserve designations, however. Rather, day-ahead generation contingency reserve awards will be settled, using standard options settlement rules, against the real-time price of *energy.*[48]

The reason we have designed New England's day-ahead ancillary services as options on real-time energy is the strong incentives this design creates. Specifically, the incentives for resources to arrange more robust energy supply (*i.e.,* fuel) arrangements are superior – *i.e.,* more efficient – when day-ahead ancillary service obligations are settled as options on real-time energy, versus a design that settles those obligations as a forward sale of real-time reserve designations. We explain

[48] Note that there is no real-time analog to the energy imbalance reserve product, as that ancillary service exists to align day-ahead market's results with the system's day-ahead forecast load. In addition, unlike generation contingency reserve, at present there are no 90-minute or 4-hour replacement energy reserve products in New England's real-time markets. Creating replacement energy reserves in the real-time markets is a possible future market design enhancement that would require additional development work, and is beyond the scope of the present filing.

the settlement of energy options in Section 4.3 next, and then address the beneficial incentives that it provides, in detail, in Section 5.

4.3 Settlement of Day-Ahead Ancillary Service Awards as Energy Options

A central feature of the new ancillary services' design is their settlement. Consistent with the conceptual logic of providing the ISO with a call on a resource's energy "on demand" during the operating day, the Energy Security Improvements will settle resources' day-ahead ancillary service obligations as a call option on real-time energy. Accordingly, each day-ahead ancillary service award will have two-settlements: one day-ahead and a second based on the price of real-time energy.

This settlement design applies a familiar, standardized multi-settlement rule that is used in a wide variety of physical commodity markets. Moreover, it functions well in concert with the existing day-ahead energy market's two-settlement design. The second (real-time) settlement is slightly different for day-ahead energy and for ancillary service positions, however, reflecting that the former is a *forward* sale (or purchase) of real-time energy and the latter is an *option* on real-time energy.

Importantly, although the day-ahead ancillary service obligations will have financial consequence, they are not "financial options." Rather, they are real options on energy – in the formal sense that their award is dependent on a resource's physical operating characteristics, and a resource's net settlement is expressly dependent on what it physically produces in real time. This real option design creates new incentives for sellers of these ancillary services to ensure they have the physical wherewithal (including fuel) to cover their obligations the next day. This is because a resource that commits to providing one of these new ancillary services will face a financial consequence in real-time settlement if the real-time energy price is high and the resource does not perform. At the same time, resources will receive day-ahead compensation to cover their costs of additional energy supply (*e.g.,* fuel) arrangements, even if it turns out that they are not needed to operate the next day.

These product design and settlement features fundamentally change the incentives present today. From a commercial standpoint, it will become profitable for the resources that the ISO relies on for these ancillary capabilities to incur the costs of maintaining reliable fuel arrangements, when such arrangements are cost effective from the standpoint of the system overall – helping ensure they can perform if dispatched to fill an energy gap, even on a day they did not expect to operate.

To illustrate and explain these properties, below we provide a series of numerical examples. For clarity, we start with a summary of how option settlements work, as applicable in the context of the new day-ahead E&AS markets. Since the same settlement logic and rationale applies to each of the new day-ahead ancillary service products, our discussion throughout this section is equally applicable to the new day-ahead energy imbalance reserve, generation contingency reserve, and replacement energy reserve products.

4.3.1 Energy Option Settlements: Simple Examples and Implications

In today's day-ahead energy market, all energy sales (and purchases) have a second settlement. That second settlement is based on the energy produced (and consumed) in real-time and the real-time energy price. In the new day-ahead E&AS market, the day-ahead ancillary services will also have a second settlement, based on those same two elements. However, as noted above, the settlement for energy and for an ancillary service is slightly different.

In this section, we summarize the settlement mechanics for the new day-ahead ancillary services and provide several simple examples. These examples mirror the established way that call options are settled in markets that clear both forward sales (and purchases) and call options for future delivery.

► **Components and mechanics.** First, the settlement components. A call option settlement involves three elements:

- the sale of the option, which occurs at the *option price,* which we denote by *V*;
- the option *strike price*, which we denote by *K*; and
- the real-time price of the good the seller is providing an option on, which in this context is real-time energy.

The strike price is a pre-defined value, set *before* sellers specify their option offer prices in the day-ahead E&AS market. The strike price, and the level at which it is set, plays a key role in the strong incentives that this day-ahead ancillary service design creates. (We'll explain that in greater detail below.) For the moment, think of the strike price as simply a threshold price level, known to all before the option is offered and the market clears.

Like a forward sale of energy, a resource that sells an energy call option has both a day-ahead settlement, and a real-time settlement. The day-ahead option settlement has two parts. The first provides a payment to the seller at the day-ahead option clearing price, *V,* for each MWh of the option sold. In the second, the day-ahead option award is then 'closed-out' based on the real-time price and the option's strike price. Specifically, for each MWh of the option sold day-ahead, the seller is charged the real-time LMP *minus* the strike price *K,* if that difference is positive. In mathematical terms, this is written as:[49]

$$-\max\{0, RT\ LMP - K\}.$$

The real-time settlement is a credit, at the real-time LMP, for the MWh of energy the resource actually produces in real-time. This real-time settlement step does not depend on the option award

[49] Note settlement sign conventions here: a negative number is a charge (debit) to the participant; a positive number is a credit. This convention is followed in all the settlement tables throughout this paper.

directly, but will (more than) offset the option's close-out charge if the resource produces energy in real-time.

Here are a few simple examples.

► **Simple settlement examples.** In each case below, assume a resource sells 1 MWh of a day-ahead ancillary service with a strike price of K = \$50 (per MWh) at an option clearing price of V = \$5 (per MWh).

First, consider several cases where the resource produces exactly 1 MWh of energy in real-time:

a) The resource produces 1 MWh in real-time and the real-time LMP is **\$60**/MWh. Its net settlement is calculated as:

$$V - \max\{0, RT\ LMP - K\} + \text{RT LMP}$$

which is:

$$\$5 - \max\{0, \$60 - \$50\} + \$60 = \$55.$$

In this case, the resource's net settlement simplifies to $V + K$. The close-out charge and real-time credit net settlement result is a payment at the strike price, K, rather than the real-time LMP, since the real-time price is higher than the strike. In that situation, standard terminology is to say the option is "in the money."

b) The resource produces 1 MWh in real-time and the real-time LMP is **\$40**/MWh. Its net settlement of:

$$V - \max\{0, RT\ LMP - K\} + \text{RT LMP}$$

evaluates as:

$$\$5 - \max\{0, \$40 - \$50\} + \$40 = \$45.$$

In this case, the resource's net settlement simplifies to V + RT LMP. The close-out charge and real-time credit net settlement results in a payment at the real-time LMP, since the real-time price is lower than the strike. In that situation, standard terminology is to say the option is "out of the money."

In summary, cases (a) and (b) show that if a resource sells 1 MWh of day-ahead ancillary service and produces 1 MWh of energy in real-time, it receives the option clearing price V and a credit of, at most, the value of the strike price K.

Next, consider a case where the resource again sells 1 MWh of a day-ahead ancillary service, but now assume it produces more than 1 MWh of energy in real time:

c) The resource produces **2 MWh** in real-time and the real-time LMP is **\$60**/MWh (*i.e.,* in the money again). Its net settlement is now:

$$V - \max\{0, RT\ LMP - K\} + \mathbf{2\ MWh} \times \text{RT LMP}$$

which is:

$$\$5 - \max\{0, \$60 - \$50\} + \mathbf{2} \times \$60 = \$115.$$

In this example, the first MWh produced in real-time 'covered' the resource's day-ahead option award, and the second is simply an additional MWh sale at the real-time price. In the calculation above, the real-time settlement therefore provides a credit for the higher quantity (*i.e.*, 2 MWh) delivered in real-time at the real-time LMP.

► **Implications for day-ahead energy and ancillary service prices.** Cases (a) and (c) have an important economic implication and interpretation. In general, in exchange for the certainty of the day-ahead option payment *V*, a seller of a call option is 'giving up' its potential gain from alternatively selling in the real-time market, if the real-time price is higher than the strike price *K.* This is in contrast to its real-time settlement if it sells its day-ahead energy *forward* and delivers the same amount in real time, which would have a real-time credit of zero.

In essence, selling energy forward is giving up the entire potential gain from selling in real-time, but selling a (call) option on energy is not giving up the entire potential gain from selling in real-time, as the resource is still paid either *K* or the RT LMP, whichever is less, if it produces energy. For that reason, call options have lower offer prices than day-ahead forward energy offer prices, and call options have lower clearing prices than forward prices for the same delivered product.

► **More simple examples.** Next, consider two cases where a resource sells 1 MWh of a day-ahead ancillary service and does *not* produce energy in real-time. As before, assume the resource sells 1 MWh of a day-ahead ancillary service with a strike price of $K = \$50$ (per MWh) at an option clearing price of $V = \$5$ (per MWh).

d) The resource produces 0 MWh in real-time and the real-time LMP is **$60**/MWh (*i.e.,* in the money). Its net settlement of:

$$V - \max\{0, RT\ LMP - K\} + \mathbf{0\ MWh} \times \text{RT LMP}$$

evaluates as

$$\$5 - \max\{0, \$60 - \$50\} + \$0 = -\$5,$$

for a net charge of $5. In this case, the resource's net settlement simplifies to $V - (RT\ LMP - K)$. The close-out is a charge to the resource, equal to the real-time LMP *less* the strike price, with no offsetting real-time credit since the resource produced zero energy.

In effect, in the real-time settlement in this situation, the option seller is paying for the ISO's cost of replacing its 1 MWh of energy with energy from the marginal resource in real-time (*i.e.,* a cost equal to the RT LMP), but only to the extent that cost exceeds the pre-specified strike price *K.*

e) The resource produces 0 MWh in real-time and the real-time LMP is **$40**/MWh (*i.e.,* out of the money). Its net settlement of:

$$V - \max\{0, RT\ LMP - K\} + \mathbf{0\ MWh} \times \text{RT LMP}$$

evaluates as:

$$\$5 - \max\{0, \$40 - \$50\} + \$0 = \$5.$$

In this case, the resource keeps the day-ahead clearing price of $5 for accepting the day-ahead ancillary service obligation, and no money changes hands in later settlements. In this case, the resource's net settlement simplifies to just *V.*

In summary, cases (d) and (e) show that if a resource sells 1 MWh of day-ahead ancillary service and it produces 0 MWh of energy in real-time, it incurs a real-time charge to cover the ISO's real-time 'replacement cost' of its undelivered 1 MWh – but only to the extent it exceeds the strike price *K.*

► **Simple examples with co-optimized real-time dispatch.** Next, we consider how the day-ahead energy option settlements work with real-time reserves. The purpose of the next two cases is to show that the day-ahead ancillary services market outcomes do not change the existing co-optimized real-time market's incentives for resources to follow their assigned real-time dispatch.

The next case examines how the settlements work when a resource is designated for reserves in real-time, rather than energy. Specifically, consider a resource that is awarded a day-ahead ancillary service (of any type), and is designated for operating reserves in real-time, and then its energy dispatch in real-time is zero.

As before, assume the resource sells 1 MWh of a day-ahead ancillary service with a strike price of *K* = $50 (per MWh) at an option clearing price of *V* = $5 (per MWh).

f) Assume the resource's real-time energy offer price is $45/MWh, the real-time LMP is $60/MWh (an "in the money" case), and the real-time reserve clearing price (RCP) is $20/MWh. The resource produces 0 MWh of energy and provides 1 MWh of reserves in real time.

In this case, its option will be settled as before in example (d), and it will be credited for its 1 MWh of real-time reserves at the RCP. Its total net settlement is:

$$V - \max\{0, RT\ LMP - K\} + \mathbf{0\ MWh} \times \text{RT LMP} + \mathbf{1\ MWh} \times \text{RT RCP}$$

which is:

$$\$5 - \max\{0, \$60 - \$50\} + \$0 + \$20 = \$15.$$

In this situation, it is economically correct that the real-time co-optimized dispatch assigned this resource's capability to real-time reserves rather than energy. This is because the real-time reserve price ($20) exceeds the resource's energy margin ($60 – $45 = $15).

Regardless of what it sold day-ahead, the resource is better off following the real-time dispatch – which, in this example, has it providing reserves instead of energy in real-time.

This case (f) illustrates an important point. Despite selling the day-ahead ancillary service (which settles as an option on *energy*), in real-time the resource is better off providing reserves than producing energy, given the real-time prices. That real-time dispatch-following property is unaffected by the sale (or not) of day-ahead ancillary services, here and generally.[50]

To illustrate that point further, note that in this example (f), if the resource had instead chosen to run in real-time (*i.e.,* to self-schedule), then it would have the net settlement of \$55 as shown in earlier case (a), and a net profit of \$10 (\$55 – \$45 cost). In contrast, in case (f), we see the resource has a higher net profit of \$15 by following its dispatch instruction in real-time. We highlight this observation because the point is important: the day-ahead ancillary services market awards do not change the existing co-optimized real-time market's incentives for resources to follow their assigned real-time dispatch.

Along a similar line, this next case considers a situation where the resource re-offers in real-time. As before, assume the resource sells 1 MWh of a day-ahead ancillary service with a strike price of K = \$50 (per MWh) at an option clearing price of V = \$5 (per MWh).

g) The resource's day-ahead energy offer price is \$45/MWh, and in real-time the resource re-offers energy at a price of \$75/MWh. The real-time LMP is \$60/MWh, and the real-time RCP is \$0/MWh. The resource produces 0 MWh of energy in real-time (as its real-time energy offer price exceeds its RT LMP).

   In this case, its option will be settled as before in case (d). Its net settlement is:

$$V - \max\{0, RT\ LMP - K\} + \mathbf{0\ MWh} \times \text{RT LMP}$$

   which is:

$$\$5 - \max\{0, \$60 - \$50\} + \$0 = -\$5.$$

   In this situation, the real-time dispatch produces an efficient outcome (given the RT LMP) in which the resource is 'buying out' its day-ahead ancillary service position in real-time, at a cost of $RT\ LMP - K = -\$10$. That buy-out cost is less than the resource's cost if it produced energy facing the same prices, which would result in a real-time loss of $RT\ LMP - RT\ Offer$ = \$60 – \$75 = – \$15.

► **Buying-out when production is uneconomic.** This case (g) has a useful economic implication in situations where a day-ahead ancillary service seller has high marginal costs for energy (in real-time), and therefore in real-time its energy production is uneconomic. In such cases, having

[50] Note that, if the RCP was lower (say, \$10) in this example, the real-time co-optimized dispatch would have dispatched this resource for energy and not designated it for real time reserves, because its opportunity cost of energy (\$60 LMP - \$40 offer cost) would exceed the RCP.

acquired a day-ahead ancillary service obligation (which settles as an option on *energy*), in real-time the resource is better off following an assigned real-time dispatch to produce zero and thereby 'buying out' its day-ahead obligation than producing energy to match its day-ahead option award.

That is true generally, whether or not the resource re-offers due to a change in (say) its fuel costs from day-ahead to real-time. We assumed it re-offers its energy at a higher price here simply to illustrate an outcome that can (and likely will) happen to resources that re-offer in practice – and showed that the market design produces the economically correct real-time incentives in this circumstance. Note that this situation is conceptually analogous to what happens today when a resource sells energy day-ahead (rather than an option on energy), and is dispatched down in real-time below its day-ahead award – it 'buys out' its day-ahead position, in a way that preserves its incentives to follow the real-time dispatch.

► **Replacement cost-based settlements.** Next, consider a case in which a resource sells 1 MWh of a day-ahead ancillary service and does *not* produce energy in real-time. Here, we'll assume the real-time energy price is high, so the unit would be in-merit if it were able to produce, but that (for any number of possible reasons) is it not able to operate in real-time.

As before, assume the resource sells 1 MWh of a day-ahead ancillary service with a strike price of K = \$50 (per MWh) at an option clearing price of V = \$5 (per MWh).

h) Assume the resource's real-time energy offer price is \$70/MWh, the real-time LMP is now \$400/MWh, and the real-time reserve clearing price (RCP) is \$0/MWh. The resource produces 0 MWh of energy in real-time.

   In this case, its option will be settled as before in cases (d) and (g), but its net settlement is a now a much larger charge because the RT LMP is higher. Its total net settlement is:

$$V - \max\{0, \mathit{RT\ LMP} - K\} + \mathbf{0\ MWh} \times \text{RT LMP}$$

   which is:

$$\$5 - \max\{0, \$400 - \$50\} + \$0 = -\$345.$$

   In this situation, the resource would be dispatched if available (as its energy offer price is less than the RT LMP). Because it is not able to operate, however, it is again 'buying out' (as in case (g)) its day-ahead ancillary service position in real-time. Since the real-time LMP is high, this comes at a steep financial consequence of $\mathit{RT\ LMP} - K = -\$350$. As a result, it incurs a net loss in real-time settlements, based on the system's high prevailing price to procure energy to replace the non-performing resource's MWh in real time.

Case (h) illustrates a key economic principle, with significant implications for sellers' incentives. In this case, the ancillary service seller is compensating the buyer (the ISO, in the immediate instance, and load, ultimately) for the replacement cost of energy that the system must incur in real-time, at the margin, if the seller cannot operate.

Though it may seem a minor detail, in these situations it is useful to note that the *incremental* replacement cost due to the ancillary service seller's non-performance is equal to *RT LMP – K,* and *not* the full value of the *RT LMP.* The economic logic here is that, when the option was purchased (by the ISO) in the day-ahead market, the system acquired the right to 1 MWh of real-time energy for an up-front price of *V,* and an incremental price of (at most) *K* in real-time. If the seller does not deliver energy in real-time, the settlement rules put the seller "on the hook" for the *incremental* cost – that is, the cost in excess of *K* – to replace its energy. In case (h), here's how that plays out:

- The marginal resource dispatched in real-time is paid, per normal real-time settlements, the RT LMP of $400/MWh to supply the 1 MWh of energy not delivered by the seller that took on the day-ahead ancillary service obligation.

- The day-ahead ancillary service seller is charged the amount *RT LMP – K* = $350 for the incremental cost (*i.e.,* in excess of *K*) to replace its energy with that of the marginal resource (which cost $400/MWh).

- The incremental price paid by the ISO for the 1 MWh of energy "covered" by its call option nets to the strike price *K*, as required:

  $400 *RT LMP for energy* – $350 *charge to the ancillary service seller* = $50 *strike.*

In that way, regardless of which resource is ultimately dispatched to supply the marginal unit of energy in real-time, the ISO (and, ultimately, consumers) acquire the 1 MWh of real-time energy at a cost of (at most) *K.* The day-ahead ancillary service seller must incur all additional costs, in excess of the strike price, to replace its energy when it does not provide energy in real-time. That incremental replacement cost borne solely by ancillary service seller is *RT LMP – K.*

► **Implications.** This replacement cost logic lies at the economic core of why call options – both in the present context and more generally – help align incentives efficiently. In particular, the obligation of a day-ahead ancillary service seller to cover its resource's incremental replacement cost at the prevailing real-time market price will strengthen such sellers' incentives to ensure their resources are able to operate reliability, relative to today's day-ahead energy market design. (That is, relative to today's day-ahead market design wherein ancillary services are not priced, nor compensated, at all).

Stated directly, in the ISO's current day-ahead market design, if a resource does not clear in the day-ahead market and does not produce in real-time, its net settlement is zero. By contrast, under the new day-ahead ancillary service design, if a resource receives a day-ahead ancillary service award and does not produce in real time when dispatched, it incurs a potentially steep financial consequence if the real-time incremental cost to replace its energy is unexpectedly high (*e.g*., during a stressed operating day). The resources that the ISO relies upon for the system's essential ancillary services in the next-day operating plan will now have significant incentives to ensure they can operate if and when dispatched during the operating day.

We will explore the incentives that this replacement-cost ancillary service market design provides further, and how it resolves the misaligned incentives problem generally, using several more detailed numerical examples in Section 5. Before doing so, however, it is useful to touch on how these energy option settlement rules work in conjunction with resources' day-ahead energy awards.

4.3.2 Day-Ahead Energy and Ancillary Service Settlements

All of the foregoing examples are special cases of a general multi-settlement system applicable when there is more than one day-ahead product. This system is particularly useful when a single resource receives both energy and ancillary services awards in the day ahead E&AS market.

Again, the settlement logic and rationale discussed below applies to each of the new day-ahead ancillary service products. Thus, our discussion here is equally applicable to the new day-ahead generation contingency reserve, replacement energy reserve, and energy imbalance reserve products.

One important point: in Section 4.2, we noted that incorporating the day-ahead load forecast into the day-ahead market will create a new source of compensation to supply resources scheduled to provide energy, and that new component will be separately priced (*see* "The day-ahead load forecast" discussion therein). That new component is not covered in this present section; we will introduce and explain it in the context of the market-clearing process for the Energy Imbalance Reserve, with the assistance of additional examples, in Section 6.

► **Example with a day-ahead energy and ancillary service award.** This next example shows the multi-settlement steps for a resource with both a day-ahead energy and an ancillary service award (awarded to different MW of the resource's capacity).

i) Assume a resource sells 1 MWh of energy and 2 MWh of an ancillary service in the day-ahead market for a particular hour the next day (again, which specific ancillary service does not matter here). During that hour (*i.e.,* in real-time), the resource produces 5 MWh of energy.

   How is this settled? The various day-ahead and real-time settlements for the two products are easiest to organize in a table, as shown below. (The day-ahead reserve clearing price, denoted in the preceding section by the price *V*, is now abbreviated RCP below). The resource's total market settlement is the sum of the five entries in the table.

	Forward Sale of Energy	Option Sale of Ancillary Service
Day Ahead Awards (credits)	2 MWh × *DA LMP*	1 MWh × *DA RCP*
Close-out of Day-Ahead Positions (debits)	–2 MWh x *RT LMP*	–1 MWh × max{0, *RT LMP – K*}
Real-Time Supply (credits)	5 MWh × *RT LMP*	

The first row shows the resource's credits (revenue) for its day-ahead market awards. In the second row, the resource's day-ahead energy position is closed-out at the real-time price, as illustrated above in settlement examples (a) thru (h). The last row shows the resource's credits for the energy actually it supplies in real-time, in this case, 5 MWh.

► **Implications.** This multi-product settlement method is commonly employed in commodity markets where participants transact both forwards and options for the same delivery time. As such, it is not a new or novel multi-settlement design by any means. In the context of a day-ahead E&AS market, though, it has two properties worth noting here.

First, the ISO's existing day-ahead energy market settlement logic, based on real-time energy deviations, can be thought of as the special case (under the Energy Security Improvements) in which the day-ahead ancillary service quantity is 0 MWh. In that special case, by setting the day-ahead ancillary award quantity (and its closed-out quantity) to 0 MWh and summing the table's five entries, we obtain

$$2 \text{ MWh} \times \textit{DA LMP} + [(5 \text{ MWh} - 2 \text{ MWh}) \times \textit{RT LMP}]$$

which is the familiar two-settlement deviation logic for energy used today. The first term is the day-ahead payment for energy at the day-ahead LMP; the second term (in square brackets) is the real-time payment for "real-time deviations from day-ahead" at the real-time LMP. In other words, this much is the same settlement of day-ahead forward energy positions in use today.

Second, this multi-settlement method avoids the need for a market participant, or the ISO, to assign or allocate a resource's real-time energy production to the resource's distinct day-ahead forward energy obligation and ancillary service obligations. Such assignments would be economically meaningless, and are unnecessary. Instead, each product's day-ahead position is separately closed out in the appropriate way without using the real-time MWh at all (*see* the second row in the table above); the resource then is credited for whatever it provides in real-time.

► **Example with a real-time reserve designation.** This next simple example shows that this multi-settlement method handles real-time reserve designations and payments (credits) for reserves gracefully.

j) Suppose that the resource in case (i) above has the same day-ahead awards as in that example. Now let's assume that it provides 5 MWh of energy in real time and, in addition, it also provides 6 MWh of real-time reserve.

   In this case, its total settlements would be the sum of the five entries in the table shown below. The only change from case (i) above is the addition of the real-time reserve credit in the last row (noted in red text for emphasis in this table).[51]

[51] We simplify here in assuming only one real-time reserve product. In practice, a resource providing real-time operating reserves would receive credit for the quantities of TMOR, TMSR, and TMNSR it provides at their respective prices.

	Forward Sale of Energy	Option Sale of Ancillary Service
Day Ahead Awards (credits)	2 MWh × *DA LMP*	1 MWh × *DA RCP*
Close-out of Day-Ahead Positions (debits)	–2 MWh x *RT LMP*	–1 MWh × max{0, *RT LMP* – *K*}
Real-Time Supply (credits)	5 MWh × *RT LMP* + 6 MWh × *RT RCP*	

Importantly, all of this works smoothly if day-ahead generation contingency reserve (that is, day-ahead TMSR, TMNSR, and TMOR) awards are settled as call options on energy, and then designated and priced in real-time based on the co-optimized real-time market in use today.

We note again here that the real-time dispatch (and the economic evaluation of any additional generation commitments after the day-ahead market, if needed) will continue to be based on resources' energy supply offers in effect during the operating day. Resources would continue to be able to re-offer if, for example, their fuel costs change during the operating day, consistent with existing market rules and procedures. And like today, day-ahead energy and ancillary services awards do not enter into the real-time dispatch calculations. In this way, the real-time dispatch of energy and reserves will continue to reflect the least-cost dispatch of the system.

► **Incentives and implications.** As noted at the start of Section 4.1, the day-ahead ancillary service products are real options on energy: settlements depends on what the associated physical resource produces in real time. Real options strengthen suppliers' incentives to invest in energy supply (or any other) arrangements that will enable them to more reliably produce on short notice, so that they can "cover the call" – that is, produce energy during the operating day if instructed to do so. In that way, the resource owner that acquires a day-ahead ancillary service obligation is able to avoid incurring the potentially steep financial consequence of buying out its call option position if the real-time price is high and it cannot perform (*e.g.,* case (h) in Section 4.3.1).

These investments have a cost, of course, and sellers of these ancillary services need to be appropriately compensated for the obligations and risks they voluntarily assume. For this reason, it is essential that the day-ahead ancillary services be biddable products. The benefit of a co-optimized day-ahead market for energy and ancillary services is that it can find the lowest clearing prices at which all awarded sellers are willing to accept their assigned obligations, and compensate them competitively for doing so.

► **Technical Notes: Option Settlement Location.** The new day-ahead ancillary services introduced by the Energy Security Improvements are system-wide products, procured to satisfy system-level reserve requirements.[52] Like the ISO's (real-time) system-wide reserve products today, each new day-ahead ancillary service product's clearing price will be uniform system-wide (*i.e.,* not zonal or locational).

[52] The specific system-wide requirements are described further in Sections 6.4.1 and 7.2.1.

For the purpose of the energy options' second settlement, this raises the issue of *which* real-time energy price should be used in the energy option close-out of day-ahead ancillary service awards. In real-time, there are both system-level energy prices and nodal energy prices.

For the energy option design, the ISO will settle all day-ahead energy call options at a system-wide real-time energy price – specifically, the Real-Time Hub Price for energy. That price is an average of the real-time LMPs for a pre-existing, stable set of (generally unconstrained) pricing nodes in the ISO's control area.[53]

The reasons that energy call option awards will be settled (that is, closed-out) using a system-wide real-time energy price is that, foundationally, these are system-level products, with uniform system-wide clearing prices, and not locational products with locational prices. If, in the alternative, the close-out charges used the nodal LMPs where resources are individually located, then their day-ahead energy call option offers would not be true substitutes in the market clearing process. That is, in that alternative, sellers that would be paid the same, uniform day-ahead clearing price for the same *nominal* system-wide product, but would in fact face different settlement rates (close-out charges) for identical performance – yet offers were cleared to meet the same system-wide demand for reserves.

Since the close-out settlement will be based on the real-time Hub energy price, the *RT LMP* notation in examples (i) and (j) above should be interpreted accordingly. That is, this settlement treatment means the RT LMP used in the option close-out step (*see* the *second* row, right column, of each table in examples (i) and (j)) is the *Hub* RT LMP. That value may differ from the actual *nodal* RT LMP applicable to a resource's settlement of (*i.e.,* credit for) its real-time energy produced (as shown in the *third* row of each table in examples (i) and (j)). These locational energy differences may arise due to congestion and marginal loss pricing in the real-time market, when congestion arises or losses differ in real-time between the Hub component locations and the day-ahead ancillary service seller's resource's location.

After reviewing these considerations with stakeholders during the past year, we have determined that using the real-time Hub Price for all energy call option settlements of the new day-ahead ancillary services preserves the uniform, system-wide nature of these products. Importantly, New England has a relatively uncongested transmission system, and as a result we do not expect this design element to prove particularly consequential, as a practical matter.

4.4 Sellers' Obligations

During the stakeholder review process for the Energy Security Improvements, the ISO stressed that a seller of day-ahead ancillary services has a "no excuses" settlement obligation. That settlement obligation uses the multi-settlement design for a call option on real-time energy, as discussed above. Importantly, and by design, those settlement charges reflect the system's incremental cost

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[53] *See* Tariff Section III.2.8.

to replace any real-time energy that a day-ahead ancillary service seller does not provide (*see* again case (h) in Section 4.3.1).

Several market participants inquired as to whether additional obligations are imposed upon a seller that receives a day-ahead ancillary service award. This question is sometimes framed in terms of whether the obligations, and the day-ahead ancillary service market more generally, is "physical" or "financial." In more precise terms, the salient questions are whether, under the new design, a seller with a day-ahead ancillary service award is obligated to arrange fuel (at any available price) for its resource, and whether it is a violation of the market rules if it has no fuel to operate in real-time.

In brief, if a seller that has no market power receives a day-ahead ancillary service award, and subsequently does not provide energy during the corresponding real-time award hour, the seller will be subject *only* to the market's settlements as specified in the revised market rules. Specifically, it will be charged based on the price of real-time energy (if that price exceeds the applicable hour's strike price).[54] In a well-designed market, that is the economically correct remedy when the seller of an energy call option does not provide real-time energy.

We do not stipulate additional obligations, in the form (say) of an obligation to acquire fuel at any available price or an obligation to demonstrate the physical unavailability to procure fuel. As we explain presently, such additional obligations should be expected to result in excessive fuel procurement expenditures, impede generators' willingness to participate in the market, and ultimately result in unnecessarily high consumer costs.[55]

► **Clarifying terminology.** The new day-ahead ancillary services market is a physical-delivery market. A market participant offering to sell day-ahead ancillary services must offer the physical capability of an identified resource when it submits its energy option offer. Moreover, with co-optimized day-ahead energy and ancillary services, the clearing of ancillary service awards is expressly based on the ramping capability and other physical parameters of that resource. In this regard, the day-ahead ancillary services market is intended to enable resources to physically deliver real-time energy commensurate with their awards (*i.e.*, in amounts and with lead-times corresponding to each resource's capabilities and its day-ahead energy schedule).

Like physical-delivery markets generally, the day-ahead ancillary services market has financial consequences for non-performance. The consequence of non-performance, given a day-ahead ancillary service award, is a net settlement charge based upon the price of real-time energy (as described in Section 4.3.1). Under the revised market rules, this market settlement charge is the consequence if a seller of a day-ahead ancillary service does not provide energy with its associated physical resource in real-time.

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[54] *See* new Tariff Section III.3.2.1(q)(2) *et seq.*

[55] As a separate point, this should not be construed as a limitation on appropriate remedies for (or deterrents to) physical withholding by a supplier with market power. A supplier that physically withholds its capability (*ipso facto*) does *not* acquire an ancillary service award; in contrast, we focus here on the obligations of a supplier that *does* acquire a day-ahead ancillary service award. Consequently, physical withholding involves different (opposite) circumstances than when a supplier acquires an ancillary service award, as discussed herein.

From a terminological standpoint, referring to day-ahead ancillary services as a physical-delivery market does not imply that day-ahead ancillary service sellers have an obligation to acquire fuel for their resource at any price (sometimes referred to as a "specific performance" obligation). A well-designed market for the physical delivery of a tangible service should be clear about the consequences for non-performance, but by no means do such consequences need to entail a specific performance obligation.

4.4.1 Layering extraneous obligations over a well-designed market is inefficient

In a well-designed market, sellers are not induced to incur costs that are greater than the benefits those expenditures bring to the system. If a day-ahead ancillary service seller is obligated to procure fuel at any available price, for instance, then the seller may incur costs that exceed the system's cost to obtain energy from an alternative resource. In aggregate, such an obligation would result in inefficiently high costs to sellers, causing higher ancillary service offer prices, reduced market participation, or both. Either would produce inefficient outcomes and unnecessarily high consumer costs.

Under the Energy Security Improvements design, a more cost-effective outcome is achieved by aligning the seller's private incentives to incur fuel-related costs with the expected replacement cost of (electricity) energy in real-time. This alignment is achieved with a simple mechanism: if a seller of a service is unable to perform (for any reason), the market will rely on the least-costly alternative resource available in real-time to replace the energy from the non-performing resource, and charge the non-performing resource's owner for the additional cost of that replacement energy. (*See* Sections 5.1.2 and 5.3.2, which explain in detail how energy options align the costs of arranging fuel supplies with the expected benefit to the system, producing cost-effective outcomes).

► **Replacement cost and real-time scarcity prices.** It is important to note that covering the real-time replacement cost is the appropriate obligation of a non-performing seller not only during normal market conditions, but also during stressed system conditions when reliability is at heightened risk. During a real-time shortage of operating reserves (or, in extreme situations, of energy), the real-time energy price that a non-performing seller is charged incorporates the system's real-time reserve shortage price(s).[56] In this way, the "replacement cost" that a non-performing day-ahead ancillary service seller is charged will not only reflect the actual cost of energy from the marginal resource, it will additionally include the (maximum) price that the system is willing to incur to reduce (and to avoid) the real-time shortage – whenever that shortage is made worse by the seller's non-performance.

Because the replacement cost charged to a non-performing seller will incorporate the "scarcity" cost of a shortage of reserves (or of energy) whenever it occurs, the seller's incentive to procure fuel is aligned with the cost the system ascribes to the shortage. That point is crucial to how the Energy Security Improvements design provides sellers with the appropriate fuel procurement incentives. Real-time

[56] This occurs to the extent an incremental MWh of energy from the seller would reduce the real-time reserve shortage. The system's reserve shortage prices are known as Reserve Constraint Penalty Factor values in the Tariff.

reserve shortage pricing is the pre-existing, Commission-approved mechanism for ensuring that the market properly signals the value of a shortage—or, stated more precisely, the value of the benefit obtained by *avoiding* the shortage. Charging a non-performing seller for the replacement cost, including this scarcity cost, when the seller's non-performance contributes to a reserve (or energy) shortage broadcasts to the seller the (maximum) cost it should incur—no more and no less—to arrange fuel in order to provide energy.

In simple terms, this mechanism—and the energy call option's market settlement rules under the new design—aligns the seller's incentives to perform with the value that the region places on avoiding a shortage, as reflected in the system's real-time reserve shortage pricing mechanism. This alignment produces cost-effective incentives for a day-ahead ancillary service seller to perform generally, and to procure fuel specifically.

► **Implications.** It should be apparent that to achieve these objectives in an economically-sound manner, the Tariff must not layer onto the market any additional obligation that forces sellers to base their fuel procurement decisions on factors *other than* the replacement cost of real-time energy (inclusive of its scarcity cost, when that occurs). Doing so not only increases sellers' fuel procurement expenditures excessively – the extra-market obligations may increase sellers' regulatory uncertainty (over a potential Tariff violation of such extra-market rules).

Sellers can reasonably be expected to reflect such extra-market costs and risks in their option offer prices for day-ahead ancillary services, thereby increasing the overall costs that consumers ultimately pay. Further, should the regulatory risk prove significant, it may undermine some sellers' willingness to participate in the day-ahead ancillary services market altogether. In this case, fuel-related obligations beyond the proper market settlements would produce an adverse "double-whammy" of inefficiently high offer prices (reflecting excessive fuel procurement expenditures) and reduced market participation by competing suppliers (due to regulatory uncertainty). Taken together, these foreseeable consequences would undermine the cost-effectiveness of the new day-ahead ancillary services design and unnecessarily raise costs to consumers.

In summary, to impose performance obligations that induce a seller to devote financial resources *beyond* the amount that it would spend facing only economically-correct market consequences for non-performance—*i.e.,* facing only market settlements based on real-time replacement cost—would be both to consumers' detriment, and inconsistent with the ISO's obligation to create and sustain economically efficient markets.[57]

4.5 Energy Option Strike Prices

A strike price is a new concept in the ISO's energy and ancillary service markets. As we explain presently, this is an important design concept because the strike price affects day-ahead ancillary service sellers' incentives to invest in energy supply (*i.e.,* fuel) arrangements.

[57] *See* Tariff Section I.1.3(b).

Fortunately, options are familiar enough in other contexts that their economic analysis provides considerable guidance. In this section, we first describe several guidelines that govern how energy option strike prices will be determined for the day-ahead ancillary services market. We then summarize various practical design elements, and their associated provisions in the revised market rules.

As a general matter, there are three important aspects that guide how strike prices should be determined in a day-ahead E&AS market design. The:

1. **Known before offers due**. The numerical value of the strike price must be known to participants in advance of when they must submit energy and ancillary service offers in the day-ahead market.

2. **At the money.** The most efficient outcomes are obtained when the strike price is set at approximately the expected value of the energy price at which the options will settle.

3. **Accurate, within limits.** In practice, small inaccuracies in setting the strike price precisely 'at the money' should not matter much.

We explain each of these guidelines, and discuss their practical ramifications for the day-ahead ancillary services market, next.

4.5.1 Strike Price Guidelines

► **Guideline 1: Known before offers due.** The first guideline requires that the market rules provide a strike price that will be fixed (or "locked down") in its numerical value prior to the offer submission window for the day-ahead market. If the strike price (K) is not fixed before offers are due, then suppliers would have no way, in advance of submitting their offers, to anticipate how much risk they will be exposed to for a given outcome of the real-time price.

Put differently, the settlement of an energy call option – and the (minimum) price a resource owner would be willing to offer to take on a day-ahead ancillary service obligation – depends explicitly on the (numerical) value of the strike price, K. This dependence can be seen in the multi-settlement table entries shown in Section 4.3.2 above (*see* examples (i) and (j), where the close-out of day-ahead positions formula includes the strike price K). If resource owners do not know the value of the strike price prior to when day-ahead offers are due, they would have no obvious way to formulate a competitive offer price for the day-ahead ancillary services.

► **Guideline 2: At the money.** The second guideline specifies that to provide efficient incentives for arranging energy supplies (at the margin), the strike price can be set at the expected value of the real-time LMP for the corresponding delivery hour. The term of art that goes with this guideline is setting the strike price "at the money." A strike price that is set materially higher than that will tend to mute incentives to invest in energy supply (*i.e.,* fuel) arrangements, undermining the performance of the day-ahead E&AS design.

The idea behind this guideline is simple. Consider the extreme case where the strike price is set very high – higher than the highest possible value of the real-time LMP. In this case, in the option's settlement, the value of the close-out of the day-ahead award would always be zero. That is, if the strike is so high that *K* > RT LMP in all situations, then the value of the close-out term, *max*{0, *RT LMP* – *K*}, is always zero (because *RT LMP* – *K* would always be less than zero). And if that were the case, the competitive clearing price of day-ahead ancillary services would also be zero, as there would never be any charge applied when resources with day-ahead ancillary service obligations fail to perform.

Ironically, the situation just described is effectively the same, from an incentive and compensation standpoint, as the energy-only day-ahead market construct we have today for resources without day-ahead energy market awards. If the option strike price is set too high, then suppliers with a day-ahead ancillary service obligation face no risk of having to incur the cost of "replacing their MWh" in real-time settlement if they do not perform; their only settlement would be a real-time credit for what they supply in real time. That's the same as what the current market design provides for the resources that are not scheduled in today's day-ahead market. Put simply, if the strike price is set too high, then incentives for suppliers to invest in arranging energy supplies in advance would not be changed from today's market design at all. A high strike price does not solve the misaligned incentives problem.

If a too-high strike price would undermine day-ahead ancillary service providers' incentives, at what strike price level would it not? Here, economics provides a sharp answer. In general, an energy option award will provide a resource with efficient incentives to cover its award (*e.g.,* to arrange fuel) if the strike price is set at, or below, the resource's marginal cost of producing energy.

To see why, consider the opposite, where the strike price is greater than a resource's marginal cost of producing energy. In that situation, there will be a range of real-time energy prices (namely, prices above its marginal cost and below the strike price) for which it would be economic for the resource to operate – *if* it has arranged fuel – but for which the resource will face no option close-out charge if it has not. And the higher the strike price is above the resource's marginal cost, the greater the potential that the resource will be in demand to serve real-time energy but face no financial consequences if it does not. Such situations would plainly undermine the resource's incentives to arrange energy supplies, even when such arrangements are beneficial (*i.e.,* cost-effective and reliability-enhancing) from society's standpoint.

Put simply, to avoid diluting a resource's incentives for cost-effective energy supply arrangements, the strike should be set at or below the seller's marginal cost of energy in real-time.[58] In application, however, that economic principle raises another issue. As a purely theoretical matter, that principle would be achieved by setting hourly, resource-specific strike prices based on each individual resource's marginal costs of energy. Such a "customized," non-uniform strike price approach would

[58] Although not obvious, a resource's incentives do not strengthen further by setting a strike price below, rather than at, its marginal cost. For example, there is no additional efficiency gain from setting a strike price at zero, rather than at a resource's marginal energy cost. We explain this in greater detail below (*see* Section 5.3).

be impractical, however, and poses other undesirable consequences.[59] Fortunately, the market provides a practical alternative that is consistent with providing economically-sound incentives.

Specifically, the desired incentives can be reasonably achieved by setting the strike price – uniformly for all resources – at the expected value of the real-time energy price (for the corresponding delivery hour). The logic here is simple. In the real-time markets, resources that have *lower* marginal costs than the real-time energy price are committed and dispatched to supply energy. Resources, or portions thereof, that have *higher* marginal costs than the real-time energy price are designated by the dispatch to supply reserves (provided they have the requisite response and ramping capabilities).[60]

Therefore, setting the strike price at the expected value of each hour's real-time energy price will serve the objective of providing a transparent, uniform strike price at or below ancillary service resources' marginal costs. By doing so, the strike price should not undermine ancillary service sellers' incentives; rather, the energy option design will maximize their incentives to make all cost-effective energy supply arrangements to ensure their resources can perform when needed.

► **Guideline 3: Accurate, within limits.** In practice, setting a strike price at the expected value of the real-time LMP for the delivery hour requires an estimate, or forecast, of the expected real-time LMP. That estimate must be provided to all participants prior to submitting bids and offers into the day-ahead market (per Guideline 1). Fortunately, small inaccuracies in setting the strike price 'at the money' should not matter much.

Forward looking forecasts of market outcomes are inherently imperfect, even if, on average, they are neither too high nor two low. The structure of resources' incentives under the energy option design suggests such inaccuracies will not tend undermine the design's performance, at least within limits. If the strike price is set too low, more resources with day-ahead ancillary service awards may have a strike price below their marginal costs; that provides no additional benefit, and may raise their option offer prices, but it does not undermine their incentives to cover their day-ahead obligations.

In the opposite direction, if the strike price is set too high – *i.e.,* higher than some ancillary service sellers' marginal costs – that may begin to reduce some sellers' incentives below what would be efficient. However, even then, those incentives may not drop abruptly (*i.e.,* not discontinuously) if the strike price exceeds a resource's marginal energy cost. We explain these technical points further, using a numerical example, in Section 5.3 below.

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[59] In particular, resource-specific strike prices would result in different close-out settlement costs for sellers with identical performance under identical market conditions. That runs contrary to a more fundamental principle of equal compensation for equal service. In addition, resource-specific strike prices makes a proper economic comparison of option offers (*i.e*., their substitutability) in the market-clearing process very difficult.

[60] There are exceptions, such as when real-time re-dispatch is needed to create reserves on a resource with a marginal energy cost below the real-time LMP. From a design standpoint, these situations argue for setting the strike price low, not for setting a strike price high, relative to the expected real-time LMP.

The bottom line is that, in theory, small inaccuracies in setting the strike price "at the money" should not impact incentives much. And, in developing practical implementations of theoretically-sound improvements to the region's market design, we are cognizant of the need to not let the perfect become the enemy of the good.

4.5.2 Strike Price Specifics and Practicalities

In this section, we summarize various practical aspects of the strike price calculation, and the corresponding supporting provisions of the revised Tariff.

► **A dynamic calculation.** As noted previously, the strike price will be based on the expected real-time price of energy. Expected real-time energy prices vary from hour-to-hour, and from day-to-day. This is because expectations of real-time prices depend on such factors as expected energy demand, weather forecasts, gas price forecasts, the hour of the day, day of week, season, and other factors. Accordingly, the strike price will vary each hour of the day; that is, there will be 24 different strike prices, one for each hour of the applicable operating day. The strike prices will be calculated and posted prior to each day's submission deadline for the day-ahead market.

Since strike prices are posted prior to the day-ahead market, the strike prices will be based on a forecast of the hourly expected real-time energy price for the (applicable) operating day. We anticipate the forecast will be a function of information including (but not limited to) the latest weather forecasts, gas prices, hour of the day and day of the week, seasons, and other data that are statistically useful for forecasting hourly real-time energy prices.

► **Context: Current practice.** Fortunately, the ISO has considerable experience developing and implementing short-term (hourly and multi-day) forecasts of gas and electricity prices. For market administration and market monitoring purposes, the ISO has developed and uses both internally-developed price forecasting tools (based on publicly-available data), and price forecasting services from specialized commercial vendors.[61]

As a practical matter, the ISO reviews and shares the methodology for internally-developed price forecasts, and publicly provides to stakeholders assessments of their performance in comparison to commercial vendors' price forecasts.[62] The underlying "state of the art" in machine-learning algorithms for these purposes continues to improve, so the ISO periodically reviews and updates its

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[61] For example, the ISO presently uses price forecasts to calculate intertemporal opportunity costs for more than 100 individual oil- and dual-fuel generators (performed daily for the next 144 hours). *See* Energy Market Opportunity Costs for Oil and Dual-Fuel Resources with Inter-temporal Production Limitations, Memorandum from the ISO's Markets Development department to the NEPOOL Markets Committee, dated September 13, 2018, available at https://www.iso-ne.com/static-assets/documents/2018/09/a10_memo_re_energy_market_opportunity_costs_for_oil_and_dual_fuel_resources_with_inter_temporal_production_limitations.docx.

[62] *See*, e.g., Natural Gas Price Forecast Method for Energy Market Opportunity Costs, Memorandum from the ISO's Markets Development department to the NEPOOL Markets Committee, dated October 9, 2018, available at https://www.iso-ne.com/static-assets/documents/2018/10/a7_memo_re_natural_gas_forecast_method_energy_market_opportunity_costs.pdf.

price forecasting methods and sources. When circumstances warrant improvements to the price forecasting process, tools, or sources, the ISO provides stakeholders with information and rationales for changes prior to changing the algorithms or commercial vendor service used in production.[63]

► **Process for strike prices.** Based upon extensive stakeholder discussions and feedback during 2019 and 2020, the ISO will use a broadly similar approach (to that described above) for the dynamic calculation of hourly strike prices. Forecasting the expected real-time energy price, in advance of the day-ahead market, for the purpose of calculating hourly strike prices, is a new application of similar price forecasting tools and systems.

As noted in Section 4.3, all energy call options are to be settled using the Real-Time Hub Price for energy. We expect the ISO's forecast process will directly estimate the expected Real-Time Hub Price, rather than the myriad real-time nodal prices that comprise the real-time Hub Price for energy.

For strike price calculation purposes, this process is to be governed by a new Section III.1.8.3 of the Market Rules in the Tariff, which has the following substantive provisions:

- Consistent with Guideline 1, the (numerical value of) the Energy Call Option Strike Price for each hour of the Operating Day will be publicly posted in advance of when bids and offers are due in the day-ahead market.

- Consistent with Guidelines 2 and 3, the Energy Call Option Strike Prices, in $/MWh, will be a forecast of the expected hourly Real-Time Hub Price for each hour of the Operating Day.

- To facilitate transparency, the forecast used to determine the Energy Call Option Strike Prices shall be based on a publicly-available forecasting algorithm. That may be an ISO-developed forecasting algorithm, a published (*e.g.* academically-developed) methodology, or other source consistent with this requirement, as proves suitable after development, evaluation, and review.

- Consistent with existing practice, the ISO will review any potential revisions to the forecasting process and algorithms, prospectively, through the stakeholder process.

The last point highlights an important practical observation. Technologies and algorithms applicable to short-term (hourly and multi-day) price forecasting, particularly those employing newer machine-learning and neural-network-based technologies, are steadily improving over time. Accordingly, the ISO anticipates periodically reviewing, and if warranted, developing technical improvements to the price forecasting process or source(s) as better algorithms become available. The provisions in this new Section III.1.8.3 are designed to enable the ISO to develop and implement such technical

[63] *See*, e.g., Energy Market Opportunity Cost Changes Taking Effect on December 3, 2019, Memorandum from the ISO's Markets Development department to the NEPOOL Markets Committee, dated November 6, 2019, available at https://www.iso-ne.com/static-assets/documents/2019/11/a7_a_memo_re_energy_market_opportunity_cost_changes.pdf.

process improvements, while providing transparency and the opportunity for stakeholder review and feedback, to the strike price calculation methodology.

4.6 Energy Option Offer Particulars

In this section, we note various rules governing energy option offers and their associated new Tariff provisions in this filing.

► **Context.** As noted at the outset of Section 4.2, the day-ahead ancillary services uses a 'one offer, multiple products' market clearing design. Participants may submit a single energy call option offer for a particular hour, not offers specific to each type of ancillary service. Stated differently, participants' energy call option offers are the *inputs* into the day-ahead market clearing process. Day-ahead obligations for each ancillary service type – Energy Imbalance Reserve, Generation Contingency Reserve, and Replacement Energy Reserve – are the *outputs* of the market-clearing process. The co-optimized day-ahead market clearing engine will determine the most cost-effective assignment of the offered energy option to meet each of the system's day-ahead ancillary service requirements.

Consistent with this 'one offer, multiple products' market clearing design and the 'at the money' principle for setting the strike price, each cleared energy option offer for a particular hour will be settled using the same strike price (namely, the system's applicable strike price for that hour of the operating day). That is, the strike price is does not vary for the different types of ancillary services awarded in a particular hour.

► **Offer particulars.** Each energy call option must be associated with a specific resource. As noted in Section 4.2, and discussed further in Section 7, the market clearing process is expressly based on resources' physical operating characteristics (ramp rates, startup lead times, maximum output levels, and the such). This will ensure that awards for each ancillary service product do not exceed the resource's capability to deliver (*e.g.* awards of GCR Ten Minute Spinning Reserve do not exceed a scheduled-to-be-online resource's upward ramping capability over ten minutes, and so forth). A resource associated with an energy call option offer must have an energy supply offer for the same hour, so the co-optimized market clearing process can account for the resource's energy schedule and its physical operating limits and capabilities (which are formally part of its energy supply offer).

Formally, under the Energy Security Improvements, an energy call option offer will comprise an offer price, an offer quantity, and the applicable hour of the next (operating) day. Offered prices and quantities may vary by hour, as is currently allowed for energy supply offers and energy demand bids offers in the day-ahead market.

An energy call option offer's price and quantity must satisfy certain limits. These are based on economic or physical considerations. Offer quantities may not be negative numbers, nor exceed the associated resource's maximum energy output (known as its "Economic Maximum" output in the existing Tarff). Offer prices may not be negative, as a negative price is not economically logical when selling a call option (the option close-out settlement always imposes a non-negative settlement cost on the participant). The tariff places a non-substantive restriction on the maximum option offer price, based on the highest Reserve Constraint Penalty Factor applicable to the new requirements. This restriction is non-substantive in that any energy call option offer submitted at an offer price higher than that value would be pointless, as it would never clear in the day-ahead market.[64]

For a particular resource, an energy call option offer may have only a single offer price; that is, energy call options may not be offered with multiple price, quantity pairs. This limitation is necessitated by technical constraints; allowing multiple segments for both a resource's energy supply offer and its energy call option could create a non-convex objective function in the market clearing engine that would be difficult (if not impossible) to co-optimize.

► **Corresponding new tariff provisions.** Consistent with the foregoing discussion of offer requirements, new Section III.1.8.2 of the Market Rules succinctly describes the Energy Call Option Offers provisions. Specifically:

- Section III.1.8.2(a) provides that an Energy Call Option much be associated with a physical resource with a concurrent energy supply offer (or, for a demand response resource, a demand reduction offer) for the same hour.
- Section III.1.8.2(b) stipulates that the Energy Call Option Offer shall specify a price, quantity, and applicable hour of the next (operating) day, and those offered values must satisfy the numerical limits described above.
- Section III.1.8.2(c) imposes the limitation of only one offer price per resource discussed above (that is, no multiple offers or multi-segment offers are permissible for Energy Call Option offers).
- Section III.1.8.2(d) addresses administrative timing and submission requirements for the day-ahead market process.

[64] *See* Section 6.4.3 (explaining that Reserve Constraint Penalty Factors limit the cost the system will incur to satisfy a reserve requirement).

5. How Energy Options Solve Misaligned Incentives

We now return to central objectives of the day-ahead ancillary service products. We will explore how these day-ahead ancillary services products change resource owners' incentives to take real actions – to incur the up-front costs of arranging energy supplies in advance of the operating day, even when that energy may not be used.

For this purpose, we revisit the prior numerical examples from Section 2 to show how this design helps solve the misaligned incentive problem (Problem 1 as described in Section 2.2) associated with today's energy-only day-ahead market construct.

Importantly, the analysis and implications provided in this section apply equally to all of the new, day-ahead ancillary service products – whether energy imbalance reserve, generation contingency reserve, or replacement energy reserve. The common incentive and efficiency properties we show next are a result of the energy call option structure of the design, and its replacement-cost settlement logic. In subsequent Sections 6 and 7, we will address pricing, clearing, and other design features that are specific to each of the three new day-ahead ancillary service products.

5.1 Example 1, Revisited: A Cost-Effective Market Solution

In this section, we show that introducing a call option on energy strengthens a resource owner's incentive to invest in energy supply arrangements that benefit the system overall. Our immediate purpose is to explain how – and why – the addition of day-ahead ancillary services, when settled as call options on real-time energy, should solve the misaligned incentive problem discussed in Section 2.

At the outset, it is useful to note that in creating a market product to solve the misalignment problem, the market must achieve two distinct, but interrelated, goals. First, it must compensate the supplier sufficiently that it will be willing to incur the (up-front) costs of arranging energy supplies, whenever that would be cost-effective from the system's standpoint. Second, that compensation cannot simply be a handout. There needs to be a well-designed financial consequence tied to whether or not the resource provides energy, so that it will be induced to follow through and undertake arrangements that benefit the system. In revisiting Example 1 next, we show how the new energy options approach achieves both of these key goals.

► **Example 1: A recap.** In Example 1 from Section 2.2.1, a 1 MW generator, without a day-ahead market position, faces an unlikely possibility that demand may be high enough for it to operate the next day. It must decide in advance whether or not to incur the cost of arranging fuel. It knows there is only a 20% chance that its resource will be dispatched (if available) the next day, so the advance fuel arrangement will, in all likelihood, not be used. The main assumptions, from Table 2-1, are reproduced below for convenience.

Table 2-1. Cost and Price Assumptions for Example 1				
	With Advance Fuel		No Advance Fuel	
	High Demand	Low Demand	High Demand	Low Demand
Up-Front Cost of Advance Fuel	$ 40	$ 40	$ -	$ -
Marginal Cost	$ 70	n/a	n/a	n/a
Energy Price (LMP)	$ 120	$ 60	$ 400	$ 60
Demand Probability	20%	80%	20%	80%

In analyzing Example 1, the key results we obtained (*see* Section 2.2.1) were:

- The expected net benefit to the system of arranging fuel (*i.e.,* expected cost savings) is 20% × ($400 – $70) = $66 by avoiding running the expensive $400 generator if demand is high, minus the $40 up-front cost of arranging fuel, for a net benefit to society of **$26.** The most cost-effective – *i.e.*, efficient – outcome for the system would be achieved if the generator makes the arrangements for fuel in advance of the operating day.

- The expected net benefit to the generator of arranging fuel in advance comes from an expected gross margin of 20% × ($120 – $70) = $10 by being able to operate if demand is high, but this is not enough to cover the $40 up-front cost of arranging fuel. The generator's expected profit is therefore a net loss, **–$30**. In other words, arranging fuel in advance is not financially prudent for the generation owner.

The main point of Example 1 was that the energy market, in its *current* form, does not provide sufficient incentives for resource owners to invest proactively in energy supply arrangements – even when such investments would be cost-effective and yield expected net benefits to the system. This is a 'market failure' to incent efficient outcomes, causing higher expected costs to society as a result.

The logic underlying this conclusion is important. As explained in Section 2, the value that society places on the fuel arrangement is based on the high price it *avoids* as a result of the investment (*i.e.,* the $400 real-time LMP in Table 2-1). However, the value the generator places on the same arrangement is based on the lower price it *receives* in the energy market with the investment (*i.e.,* the $120 real-time LMP in Table 2-1). This value difference is the heart of the misaligned incentives problem: a divergence between the social and private benefit of the investment.

5.1.1 Example 1 with a Day-Ahead Ancillary Service Award

Now let's examine how the outcomes change if the generator in Example 1 has an ancillary service award, settled as a call option on energy under the Energy Security Improvements. Our point is to illustrate that such a product serves to align the incentives properly: the generator will find it in its private interest to arrange fuel in advance of the operating day, when that action is cost-effective from the system's standpoint.

In the discussion next, we do not specify whether the specific day-ahead ancillary service product here is for energy imbalance reserve, generation contingency reserve, or replacement energy reserve; the discussion is equally applicable to any of those products.

We now extend Example 1 to include the new day-ahead ancillary service products, making the following assumptions about the prices of those products:

- The option price ("*V*," in the nomenclature of Section 4) – that is, the day-ahead clearing price for reserve – is $50/MWh.

- Assume the strike price ("K," in the nomenclature of Section 4) is $120/MWh.

The first assumption will be sufficient for this generator to be willing to accept the day-ahead ancillary services obligation, given the strike price. This will be apparent after a few initial calculations, provided below.

The strike price for this example matches the real-time LMP in the high demand scenario, when the generator has arranged fuel. For the moment, this particular strike price is an assumption of convenience (to simplify calculations). The conclusions of this example would be unchanged if the strike price was lower than $120/MWh, but not if it was higher; we explain why in Section 5.3 subsequently.

Table 5-1 shows the generator's expected net revenue, for the case where it arranges fuel and the case when it does not. In row [1], we show that the generator receives the $50 day-ahead clearing price (the option price) for its 1 MWh day-ahead ancillary service award. If real-time demand turns out to be high, the generator is paid the real-time LMP of $120/MWh, and incurs its cost to arrange fuel of $40 and marginal cost of $70, for a scenario net revenue of $60/MWh in row [8] ($170 minus $110). If demand is low and it has arranged fuel, it does not operate. In that case, the $50 day-ahead price for reserve covers its $40 cost of arranging fuel, for a scenario net revenue of $10 in row [8]. Its expected net revenue, if it arranges fuel, is therefore $20 (as shown in the bottom-left cell in row [10]). Arranging fuel is now a profitable endeavor, even though there is an 80% chance the arrangement would not be used.

Table 5-1. Generator Expected Net Revenue for Example 1, With Option Award								
			Advance Fuel			No Advance Fuel		
Generator's Market Settlement			High Demand	Low Demand		High Demand	Low Demand
[1]	Day-Ahead Award	*DA RCP*	$ 50	$ 50		$ 50	$ 50
[2]	Day-Ahead Close-Out	-max{0, *RT LMP* - *K* }	$ -	$ -		$ (280)	$ -
[3]	Real-Time	*RT LMP*	$ 120	$ -		$ -	$ -
[4]	Total Settlement	[1]+[2]+[3]	$ 170	$ 50		$ (230)	$ 50
Generator's Costs							
[5]	Advance Fuel	*F*	$ (40)	$ (40)		$ -	$ -
[6]	Marginal Cost	*MC*	$ (70)	$ -		$ -	$ -
[7]	Total Cost	[5]+[6]	$ (110)	$ (40)		$ -	$ -
Generator's Net Revenue							
[8]	Scenario Net Revenue	[4]+[7]	$ 60	$ 10		$ (230)	$ 50
[9]	Demand Probability	*p* or (1-*p*)	20%	80%		20%	80%
[10]	**Expected Net Revenue**	SumProd [8]*[9]	**$20**			**($6)**	

Now consider the generator's revenue if it did not arrange fuel in advance. It again receives the $50 day-ahead price for its day-ahead ancillary service award in row [1]. If demand is low, it does not run and incurs no costs, for a scenario net revenue of $50 (as shown in the last column of row [8]). If demand is high, however, it would not be able to operate without fuel arrangements. In this scenario, its cost to settle (or 'buy out') of its day-ahead ancillary service position in real-time settlements, given the high $400 real-time LMP, is

$$\max\{0, RT\ LMP - K\} = \max\{0, \$400 - \$120\} = \$280.$$

This is shown as a negative value in row [2] because it is a cost to the generator. Its net revenue in this scenario is $50 – $280 = – $230, a net loss, as shown in row [8]. Taking the scenario likelihood-weighted average, its expected net revenue if it does not arrange fuel in advance of the operating day is a net financial loss of $6, shown in row [10].

Of course, we haven't fully "closed the loop" on this generator's decisions yet. Specifically, This example also shows that the generator would be willing to accept the day-ahead option award, given a clearing price of $50, assuming the generator is seeking to maximize its expected profit. As Table 5-1 shows, in row [10], the generator would now find it financially prudent to incur the $40 cost of arranging fuel in advance, a decision that yields an expected net revenue of $20.

In fact, revisiting Table 2-2 in Section 2.2.1 demonstrates that, in this example, an expected profit-maximizing generator would be willing to accept a day-ahead ancillary service award price as low as (just above) $30, as that would yield a greater profit than the $0 net revenue it would obtain under its best alternative without a day-ahead ancillary services award. Indeed, if this was a broader example with many competitors, this generator's (lowest) profitable offer price for the day-ahead reserve obligation would therefore be (just over) $30/MWh.

► **Implication.** The main point here is simple, and important. Real options change behavior – in this case, the generator's willingness to undertake a costly investment in arranging fuel that may not be used. In this example, that willingness arises because the generator's valuation of the investment (the $40 up-front cost to arrange fuel) is no longer based solely on the $120 real-time LMP it receives (at best) when it has fuel. Instead, its valuation of the investment is also based on the $400 real-time LMP that society *avoids* if it makes the investment. Mathematically, this occurs because that $400 real-time LMP enters into the generator's cash flows in row [2], when it is in demand but cannot operate. In that case, as noted above, it incurs a charge in the ancillary service market settlement in the amount of:

$$1 \text{ MWh} \times \max\{\, 0, \$400 \; \textit{RT LMP} - \$120 \; \textit{strike} \,\} = \$280.$$

Conceptually, the generator is now basing its decision on the same high cost that the system would incur *to replace the generator's output*, even though there is an unlikely (*i.e.,* only 20%) chance that the generator is needed to meet demand.

In this manner, the Energy Security Improvements' option settlement design aligns the generator and society's incentives to focus on the same, high $400 avoided cost. Selling the option leads the generator to internalize, in its financial calculus, the high cost that may prevail if it cannot operate when its generation is in demand.

5.1.2 Energy Options Provide Economically-Appropriate Incentives for Cost-Effective Energy Supply Arrangements

There is a second important implication of this energy option example. We stated earlier (in Section 4.3) that with day-ahead ancillary services that settle as options on energy, it becomes profitable for generators to pay the up-front costs of maintaining reliable fuel arrangements *when such arrangements are cost effective* from the standpoint of the system overall. Let's focus on that cost-effective attribute now. It implies there are limits to the costs the generator would be willing to incur up-front – but those limits align with the limits on what society would find beneficial.

To see why in the context of Example 1, recall that with a $40 up-front cost to arrange fuel in advance, the expected cost savings to the system are $26. That means the *most* society would be willing to incur, from the standpoint of cost-effectiveness, would be a $66 up-front cost to arrange fuel in advance. In that situation, the expected benefits and expected costs would be equal.

Now consider the case if the up-front cost is even higher – let's assume, for the moment, it is $75. In that case, the expected (value of the) benefit to the system of arranging fuel (*i.e.,* expected cost savings) is 20% × ($400 – $70) = $66 by avoiding running the expensive $400 generator if demand is high, minus the now **$75** up-front cost of arranging fuel, for a net benefit to society of $66 – $75 = **–$9**. In this case, from the system's standpoint, the investment in advance fuel arrangements is not cost-effective; it would be more cost-effective just to run the high-cost $400 generator in the unlikely (*i.e.,* 20%) chance that demand is high.

Does this align with the generator's incentives, in a market that provides it with the opportunity for a day-ahead ancillary service award? Yes – the generator would not find the investment cost-effective either, at a now $75 up-front cost. To see this, note that if the up-front cost is now $75, then the entries in row [5] in Table 5-1 would change from negative $40 to negative $75, a difference of $35, and the generator's expected net revenue in the bottom row of Table 5-1 – in the case where it arranges fuel in advance – would drop by $35, to become a net financial *loss* of $15 ($20 – $35 = –$15)**.** Facing that prospect, the generator's prudent financial decision would be to not incur the $75 up-front cost of cost of arranging fuel in advance, in which case its expected net revenue would be zero (*see* Section 2.2.1, Table 2-2, bottom right cell). And, as explained in the previous paragraph, this outcome aligns with society's interests as well.

One can do this same exercise with a range of possible up-front investment costs, with the same pattern of conclusions. The generator would find it financially prudent to invest if the up-front cost of arranging fuel is up to $66, but not any higher.[65] That matches, exactly, the maximum investment that would be cost-effective from society's perspective as well. Again, the reason is simple: the option settlement design is (explicitly) based on the generator internalizing, in its financial calculus, the replacement cost of energy in real-time if the generator is unable to perform.

This conclusion might seem to be an artifact of the particular numbers chosen for Example 1, but that is not the case. The conclusion illustrated here is a general property. Providing generators with the opportunity to compete for day-ahead ancillary service awards that are, in real-time, settled as call options on energy make it financially prudent for a generator seeking to maximize its expected profit to incur the up-front cost of arranging energy supplies in advance – but only when those arrangements would be cost-effective from society's standpoint as well.[66]

5.2 Example 2, Revisited: Day-Ahead Options with Real-Time Reserves

In this section, we revisit the misaligned incentives problem that arose with multiple generators in Example 2 in Section 2.8. As with Example 1, we show that introducing a call option on energy as a day-ahead ancillary service improves resource owners' incentives to invest in energy supply arrangements, to the benefit of the system overall.

The central point of this example is to again illustrate, in a more complex setting with multiple generators and multiple products, how and why introducing day-ahead ancillary services, when settled as call options on real-time energy, provides stronger and more efficient incentives than the

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[65] It may seem initially curious that this generator, with a day-ahead payment of $50, would spend up to $66 to arrange fuel in advance of the operating day. The reason is that in addition to its day-ahead payment of $50, by arranging fuel then has expected energy net revenue of $10 (a 20% chance of high demand with a $120 LMP – $70 marginal cost yields a $10 expected energy margin), and it *avoids* the $6 expected net loss if it does not arrange fuel (*see* Table 5-1, row [10]). The maximum it would be willing to spend to arrange fuel is therefore $50 + $10 + $6 = $66.

[66] In Sections 2.2.2 and 2.4.2, we also provided several variations on Example 1 with different assumptions (*e.g.,* when PFP applies). It can be shown that these same conclusions about the efficacy of the day-ahead ancillary service award hold for all of those Example 1 variations as well (we omit the detailed calculations here).

existing energy-only day-ahead market. It does so by resolving the misaligned incentives problem discussed in Section 2.

The structure of Example 2 lends itself to two additional points, which we highlight here. First, this example will show how day-ahead ancillary services, when settled as call options on real-time energy, work in concert with the real-time reserve settlements, based on the designations and prices from the real-time co-optimized dispatch in use today. We emphasized this approach earlier in Section 4.3, where we initially noted the combined day-ahead ancillary service and real-time reserve settlement logic (*see* case (j) in Section 4.3.2).

Second, in this example, the total market revenue – and therefore the total E&AS payments by wholesale buyers (and, ultimately, by consumers) – is higher under the Energy Security Improvements design than under the existing energy-only day-ahead market. This is true even though the new design produces more efficient outcomes – that is, the power system operates more cost-effectively (at lower total production costs) overall. We expect these observations to hold in practice.[67] The principal reason for the increase in total day-ahead market payments is that the market will now compensate suppliers, at transparent, competitive prices, for the ancillary services that the ISO has always relied upon in preparing the system's next-day operating plan. Suppliers are not compensated for those nonetheless-relied-upon services today, to the detriment of a cost-effective system.

► **Example 2: A recap.** In Example 2 from Section 2.8, there are four generators that can provide both energy and operating reserve. Real-time demand is uncertain, and the higher-cost generators (Generator 3 and Generator 4) do not receive day-ahead market energy awards. Generator 3 faces the possibility that real-time demand may be high enough for it to operate the next day, and it must decide whether or not to incur the cost of arranging fuel in advance of the operating day. The main assumptions, from Table 2-5, are reproduced below for convenience.

The additional market-level assumptions for Example 2 are a day-ahead energy demand of 190 MWh for the hour, and a reserve requirement (now both day-ahead and real-time) of 30 MWh for the hour.

[67] These observations are consistent with the principal findings of the Impact Assessment. In most cases studied, the Energy Security Improvements result in higher total energy and ancillary service market *payments* to suppliers overall, and simultaneously *lower* total production costs. *See* Impact Assessment at Table 22 (Difference in Production Costs, Winter Central Case), Table 25 (Total Payments, Winter Central Cases), and Table 35 (Non-Winter Total Payments, Non-Winter Central Cases).

Table 2-5. Assumptions for Example 2			
Generator	**Capacity (MW)**	**Offer Price ($/MWh)**	**Reserve Capability (MW)**
Gen 1	100	$25	10
Gen 2	100	$30	20
Gen 3	50	$40	30
Gen 4	50	$90	40
Additional Cost Assumptions for Generator 3			
		Marginal Cost	**Up-Front Cost**
With Advance Fuel Arrangements		$40	$150
No Advance Fuel Arrangements		N/A	N/A
Real-Time Demand Scenarios			
	Low Demand	**Medium Demand**	**High Demand**
Energy Demand (MWh)	170	190	210
Scenario Probability	33%	33%	33%

In analyzing Example 2 in Section 2.8, the key results we obtained were:

- The expected system total production cost is **$5,233** for the hour, if Generator 3 arranges fuel in advance of the operating day, and **$5,400** if it does not. (*See* Tables 2-6 and 2-7 in Section 2.8.1). This difference, or $167, is more than enough to cover the $150 up-front cost of the fuel arrangements. Thus, the most efficient, cost-effective outcome for the system would be achieved if Generator 3 makes the arrangements for fuel in advance of the operating day.

- If Generator 3 does not arrange fuel, it produces zero energy in real-time (in any demand scenario) and its expected net revenue is $0. If it does arrange fuel, Generator 3's expected net revenue is a net financial loss of $150. (*See* Table 2-8 in Section 2.8.2). In other words, arranging fuel in advance was not financially prudent for Generator 3.

- Under the current energy market construct, which does not provide sufficient incentive for Generator 3 to arrange fuel, the expected total day-ahead and real-time market settlement is **$6,100** for the hour. (*See* Table 2-7 in Section 2.8.1).

From the analysis of these results in Sections 2.8, our principal conclusion is that that the energy market, in its *current* form with real-time co-optimized energy and reserves, would not provide sufficient incentives for Generator 3 to incur the cost of arranging energy supplies in advance – even though making those arrangements would be cost-effective from the system's standpoint. Under the status quo, the generator's incentives are misaligned with society's interest in operating an efficient, least-cost power system.

5.2.1 Example 2 with Day-Ahead Ancillary Services as Energy Options

Now let's examine how the outcomes change if Generator 3 has a day-ahead ancillary service award defined (and settled) as an option on real-time energy. Our point is to illustrate that such a product serves to align the incentives properly: Generator 3 will find it in its private interest to arrange fuel in advance of the operating day, and that action is cost-effective from the system's standpoint.

As in Section 2.8, the timeframe in this updated version of Example 2 is a single delivery hour. Since Example 2 focused on co-optimization of energy and operating reserves, it will be useful to interpret the day-ahead ancillary service here as specifically providing the new generation contingency reserve day-ahead ancillary service. The broader conclusions below are not restricted by that interpretation, however. As in Example 2 earlier, we assume (for simplicity) a single day-ahead ancillary service product and a single real-time operating reserve product.

We make the following assumptions about day-ahead ancillary service pricing:

- The strike price is $35/MWh. This is approximately the average value of the real-time LMP in this example, consistent with the concepts discussed in Section 4.5 on strike prices.

- The day-ahead ancillary service offer price from low-cost Generator 2 is $1.67/MWh, from medium-cost Generator 3 is $11/MWh, and from high-cost Generator 4 is $17/MWh.[68]

The assumptions about the offer prices for day-ahead ancillary services from Generators 2, 3, and 4 are consistent with profitable offers for those services from each generator, given the competition they face in the day-ahead market (with one another) for both energy and for ancillary services, under the assumption that their costs of arranging fuel in advance of the operating day to cover a day-ahead ancillary service award are $100, $150, and $150, respectively. Since Generator 3 was assumed to have an up-front cost of arranging fuel of $150 throughout Example 2, the substantive new assumption is that Generator 2's cost is lower (at $100), and Generator 4's (at $150) is no less than Generator 3's.[69]

► **Day-ahead market awards and clearing prices.** With the above setup, we first evaluate the day-ahead E&AS market outcomes. This will differ from the day-ahead market outcome when there was no day-ahead ancillary service, shown previously in Figure 2-1 in Section 2.8.1.

The day-ahead market outcome with both energy and the day-ahead ancillary service is shown in Figure 5-1. The two lower-cost generators (Generator 1 and Generator 2) receive day-ahead energy

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[68] In Example 2 with a strike price of $35/MWh, the expected close-out cost for the energy option is $1.67/MWh and that is the minimum price at which a low-cost seller would be willing to accept a day-ahead ancillary service obligation.

[69] The salient assumption here is the ordering of these up-front costs among the higher-cost generators (*i.e.*, that Generator 4's are similar to, or greater than, Generator 3's). This example's conclusions would generally follow with different numerical values that respect these cost relationships.

awards, and Generator 2 and Generator 3 receive day-ahead ancillary service awards. The total ancillary services procured (just) satisfies the day-ahead requirement of 30 MWh for the hour.

The marginal ancillary services provider is Generator 3, which sets the day-ahead ancillary service clearing price at its ancillary service offer price of $11/MWh.

The day-ahead LMP is $39.33/MWh, and reflects the pricing of *both* energy and ancillary services offers. Specifically, the highest-priced offer for energy cleared in the day-ahead market is that of Generator 2, at $30/MWh. The LMP is not set by just one generator's offer price, however. It is set by the change in the system's total production cost that would be incurred if there were another increment of energy demand. That, in turn, would require a "re-dispatch" of the ancillary services awards, which produces the $39.33/MWh day-ahead LMP for energy.

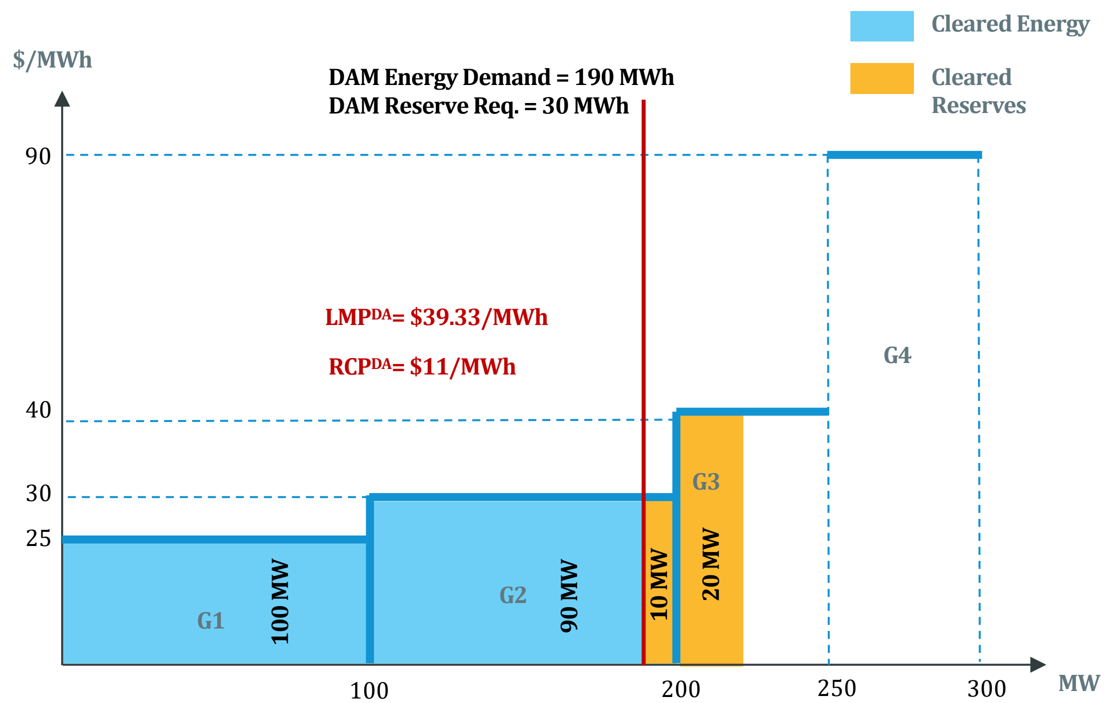

Figure 5-1. Day-Ahead Market Outcomes for Example 2, with Energy and Ancillary Service

To see this more precisely, let us step through this "re-dispatch" logic. Suppose day-ahead energy demand increased from 190 MWh, by 1 additional MWh. The least-cost solution would then increase the energy cleared from marginal Generator 2, at an incremental cost of $30/MWh (its energy offer price). However, that additional cleared energy reduces Generator 2's available MWh for ancillary services by 1 MWh, from 10 MWh to 9 MWh. To replace that 1 MWh of ancillary service and still satisfy the day-ahead ancillary services requirement, the market would then clear 1 additional MWh of ancillary service from Generator 3. The net cost of this "re-dispatch" of 1 MW of ancillary service from Generator 2 (which offered the ancillary service at $1.67/MWh) to Generator 3 (which offered at $11/MWh) is therefore the difference in their offer prices, or $11 – $1.67 = $9.33/MWh. Putting it all together, the incremental cost of another 1 MWh of *energy* demand, while still maintaining the day-ahead ancillary service requirement, is $30 + $9.33 = $39.33/MWh. The day-ahead LMP for energy is, therefore, $39.33/MWh.

In this way, creating a day-ahead co-optimized E&AS market raises the day-ahead energy price – and the revenue of all day-ahead cleared resources with energy awards – relative to a day-ahead energy market alone. With the day-ahead ancillary service, the day-ahead LMP is $39.33/MWh; by contrast, in Example 2 without the day-ahead ancillary service, the day-ahead LMP was only $30/MWh (*see* Table 2-6 in Section 2.8.1).

That is a broader and general point; while the day-ahead E&AS market clearing will not *always* produce a higher day-ahead energy compensation than would a day-ahead energy-only market, the co-optimization of energy and ancillary services will tend to produce that outcome (depending, in practice, on resources' offers, demands, and so on). We will explain this point further, with additional examples, in Sections 6 and 7.

The day-ahead E&AS clearing here also illustrates another, more subtle observation: with a co-optimized E&AS market with ancillary service *offers,* the LMP for energy may not be set by the offer price of any one resource alone. Rather, it may be set by a combination of several resources' energy and ancillary service offer prices. In this way, the day-ahead price of energy may commonly reflect one (or more) suppliers' offer prices.

► **Full market awards and outcomes.** The real-time market outcomes for Example 2 with the day-ahead E&AS market remain unchanged from those shown previously in Example 2 in Section 2.8.1. (*See* Figures 2-2, 2-3, and 2-4.)

For reference, the full set of market outcomes for the case when Generator 3 arranges fuel in advance (Case A) are shown in Table 5-2 below; and when Generator 3 does not arrange fuel in advance (Case B), in Table 5-3 below. Cell differences from Table 5-2 to Table 5-3 are shaded in light orange in Table 5-3 to facilitate comparisons.

We will address Generator 3's decision next, and then turn to the implications for total system production costs and total market payments (shown in rows [9] and [11] of Tables 5-2 and 5-3) in subsequent Section 5.4.3.

Table 5-2. Market Outcomes for Example 2 with Day Ahead E&AS Market, Case A: Generator 3 With Fuel										
		Day Ahead		**Real-Time Market Outcomes**						
		Market Awards		**Low Demand**		**Medium Demand**		**High Demand**		
	Generator	Energy	Option	Energy	Reserve	Energy	Reserve	Energy	Reserve	
[1]	Gen 1	100	0	100	0	100	0	100	0	
[2]	Gen 2	90	10	70	20	90	10	100	0	
[3]	Gen 3	0	20	0	30	0	30	10	30	
[4]	Gen 4	0	0	0	40	0	40	0	40	
[5]	**Totals**	190	30	170	90	190	80	210	70	
[6]	**Clearing Price**	$39.33	$11.00	$30.00	$0	$30.00	$0	$40.00	$0	
[7]	Scenario Total Production Cost			$4,600		$5,200		$5,900		
[8]	Demand Probability			33%		33%		33%		
[9]	**Expected Total System Production Cost**					**$5,233**				
[10]	Scenario Market Payments (incl. DAM)			$7,203		$7,803		$8,453		
[11]	**Expected Total Market Payments**					**$7,819**				

Table 5-3. Market Outcomes for Example 2 with Day Ahead E&AS Market, Case B: Generator 3 Without Fuel										
		Day Ahead		**Real-Time Market Outcomes**						
		Market Awards		**Low Demand**		**Medium Demand**		**High Demand**		
	Generator	Energy	Option	Energy	Reserve	Energy	Reserve	Energy	Reserve	
[1]	Gen 1	100	0	100	0	100	0	100	0	
[2]	Gen 2	90	10	70	20	90	10	100	0	
[3]	Gen 3	0	20	0	30	0	30	0	0	
[4]	Gen 4	0	0	0	40	0	40	10	40	
[5]	**Totals**	190	30	170	90	190	80	210	40	
[6]	**Clearing Price**	$39.33	$11.00	$30.00	$0	$30.00	$0	$90.00	$0	
[7]	Scenario Total Production Cost			$4,600		$5,200		$6,400		
[8]	Demand Probability			33%		33%		33%		
[9]	**Expected Total System Production Cost**					**$5,400**				
[10]	Scenario Market Payments (incl. DAM)			$7,203		$7,803		$7,953		
[11]	**Expected Total Market Payments**					**$7,653**				

5.2.2 Generator 3's Decision with the Day-Ahead Ancillary Service Award

Given these market outcomes, let's now examine what decision maximizes Generator 3's expected net revenue. For this, we make use of the full market outcome results (in Tables 5-2 and 5-3) with the day-ahead E&AS market and the general energy-option settlement rules, as discussed in Section 4.3. Table 5-4 shows Generator 3's expected net revenue, for the case where it arranges fuel (Case A) and the case when it does not (Case B).

Table 5-4. Generator 3's Expected Net Revenue for Example 2 with Day-Ahead E&AS Market

			Case A: With Advance Fuel			**Case B:** No Advance Fuel		
Generator's Market Settlements		Calculation	Low Dmd	Med Dmd	High Dmd	Low Dmd	Med Dmd	High Dmd
[1]	Day Ahead Energy	*DA LMP * Qe_DA*	$ -	$ -	$ -	$ -	$ -	$ -
[2]	Day Ahead Energy Close-Out	*-RT LMP * Qe_DA*	$ -	$ -	$ -	$ -	$ -	$ -
[3]	Day Ahead Option	*DA RCP * Qo_DA*	$ 220	$ 220	$ 220	$ 220	$ 220	$ 220
[4]	Day Ahead Option Close-Out	*-max(RT LMP-K, 0)* Qo_DA*	$ -	$ -	($100)	$ -	$ -	($1,100)
[5]	Real-Time Energy	*RT LMP * Qe_RT*	$ -	$ -	$ 400	$ -	$ -	$ -
[6]	Real-Time Reserves	*RT RCP * Qr_RT*	$ -	$ -	$ -	$ -	$ -	$ -
[7]	**Total Settlement**	[1]+[2]+[3]+[4]+[5]+[6]	$ 220	$ 220	$ 520	$ 220	$ 220	$ (880)
Generator's Costs								
[8]	Advance Fuel	*F*	$ (150)	$ (150)	$ (150)	$ -	$ -	$ -
[9]	Variable Cost	*MC*	$ -	$ -	$ (400)	$ -	$ -	NA
[10]	**Total Cost**	[8]+[9]	$ (150)	$ (150)	$ (550)	$ -	$ -	$ -
Generator's Expected Profit								
[11]	Scenario Net Revenue	[7]+[10]	$ 70	$ 70	$ (30)	$ 220	$ 220	$ (880)
[12]	Demand Probability	*p* or (1-*p*)	0.333	0.333	0.333	0.333	0.333	0.333
[13]	**Expected Net Revenue**	SumProd [11]x[12]		$37			($147)	

In row [3] of Table 5-4, we show that Generator 3 receives a day-ahead market ancillary service credit of $220, on an award of 20 MWh of ancillary service at the $11 day-ahead clearing price for the ancillary service (shown as 'DA RCP' in row [3]).

In row [4], we show its close-out of its day-ahead option award settlement. In Case A, the real-time LMP in the high demand scenario is $40/MWh, just above the strike price of $35/MWh, so this settlement amount is a charge of $100:

$$– 20 \text{ MWh} \times \max\{0, \mathit{RT\ LMP} – K\} \;=– 20 \text{ MWh x } \max\{0, \$40 - \$35\} \;=\; – \$100.$$

In Case B, where the generator does not have fuel, the real-time LMP in the high demand scenario is $90/MWh so this settlement amount is a much greater charge:

$$– 20 \text{ MWh} \times \max\{0, \mathit{RT\ LMP} – K\} \;=– 20 \text{ MWh x } \max\{0, \$90 - \$35\} \;=\; – \$1100.$$

Next, rows [5] and [9] show that the generator's energy revenue and variable fuel costs are a wash. This is because Generator 3 offered energy at its marginal cost and sets the real-time LMP in the only scenario when it produces energy, so it has no energy margin on its real-time energy output. Row [8] shows Generator 3's $150 up-front cost of arranging fuel, for the Case A scenarios when it does so.

The bottom row of Table 5-4 summarizes the results. Generator 3's expected net revenue, if it arranges fuel, is now $37. Arranging fuel is now a profitable endeavor, even though there is only a 33% chance it would be used. Compare this with Generator 3's decision when there is no day-ahead ancillary services market, as shown in Table 2-8 (*see* Section 2.8.2). In that earlier version of this example without the energy option design, it was not in Generator 3's financial best interest to arrange in advance for fuel, and hence did not run at all and had expected net revenue of zero.

Last, Table 5-4 shows that if Generator 3 clears the day-ahead ancillary services position of 20 MWh, but then does not arrange fuel, its expected net revenue is a financial loss of $147. Stated simply, the risk of financial loss if a supplier sells day-ahead ancillary services and does *not* arrange fuel in advance of the operating day creates the economically-correct consequence to solve the mis-aligned incentive problem – and to address the region's fuel security concerns.

The immediate point to emphasize is that with day-ahead ancillary services settled as call options on energy, and a co-optimized day-ahead E&AS market, Generator 3 would be willing to incur the $150 up-front cost of arranging fuel in advance of the operating day. Indeed, in this example, Generator 3 would be willing to accept a day-ahead ancillary service award at a clearing price down to (just above) $9.17/MWh, as that would yield a positive expected profit – still better than the zero expected net revenue it would obtain under its best alternative without a day-ahead ancillary services award (*see* Section 2.8.2, Table 2-8, bottom right cell).

5.2.3 Implications: The Incentives of Replacement-Cost Settlements

The implication of this example, and our reason for revisiting it, is important: the opportunity to sell a real option on energy, as a day-ahead ancillary service, improves the generator's willingness to undertake a costly investment in arranging fuel – even knowing that the arrangement may not be used.

In this example, that willingness arises because the generator's valuation of the investment is no longer based solely on the $40/MWh real-time LMP that it earns when it has fuel and supplies energy in real-time. Instead, its valuation of the investment is also based on the $90/MWh real-time LMP that society *avoids* if it makes the investment. This $90/MWh real-time energy price is accounted for in the generator's financial calculus in row [4] of Table 5-4., where it drives the steep $1,100 charge if Generator 3 fails to cover its day-ahead ancillary service position by not arranging fuel, and the high-demand scenario where it would be called to operate (if available) occurs.

As noted previously, this function of real-option settlements is quite general, as it aligns the generator's and society's incentives to similarly account for the same, high $90/MWh cost of "replacing" Generator 3's energy whenever it holds an ancillary service obligation but does not perform. As a result, there is no divergence between the value that society places on the investment in its energy supply arrangements, and the value that the generator places on the same investment. The real-option design of the day-ahead ancillary service product solves the misalignment problem, and would lead the generator to incur the fixed costs of making energy supply arrangements whenever they would be cost-effective for the system as a whole.

That property is a general one with this real-option design of a day-ahead E&AS market. We could create numerous additional examples, but they would all demonstrate the same conclusion: a real-option design of a day-ahead E&AS market aligns a resource owner's incentives to invest in energy supply arrangements with the replacement cost that society would incur, at the margin, if it fails to do so. As a result, there will no longer be a divergence between the social and private benefit of the investment. Put succinctly, this market design solves the misaligned incentives problem.

For completeness, it is important to emphasize that this does not imply lower levels of total payments by wholesale buyers (or, ultimately, consumers). Under the status quo, when Generator 3 was not incented to arrange fuel (and the higher-cost generator must be used in its place during high-demand scenarios), the total market payments were $6,100 (*see* Table 2-7 in Section 2.8.1, bottom row). Under the day-ahead E&AS design, where Generator 3 arranges fuel in advance and the system's expected total production costs are *lower,* the total market payments are *higher*, at $7,819 (*see* Table 5-2, bottom row).

The reason for this increase in total market payments is that the new day-ahead E&AS market is now compensating resources for the ancillary services capabilities that the ISO, and ultimately consumers, rely upon as part of the system's next-day operating plan – but that are not presently compensated in the existing market construct. With the day-ahead E&AS market design, the market will now signal, through transparent prices, the total cost of maintaining a reliable power system.

5.3 The Strike Price Creates Economic Incentives

In the examples above, we showed how the energy option design strengthens generators' incentives to arrange fuel. Further, the additional costs that generators are willing to incur to make those arrangements, in light of the new day-ahead ancillary service market with its option-based settlement, are fully aligned with the system's benefits from doing so.

There is one important design element that these conclusions rest upon that merits additional discussion. As noted in the Section 4.5 discussion on energy option strike prices, these beneficial incentive properties are dependent on the strike price not being set 'too high.' If it is, these incentives may be undermined and the benefits of the Energy Security Improvements would be lessened.

In this section, we provide a more detailed rationale for how the strike price should be set to achieve efficient incentives. This analysis also will help to clarify why, in practice, small inaccuracies in setting the strike price should not matter much, within limits (*see* Guideline 3 in Section 4.5.1).

5.3.1 Incentive Profiles

In Section 4.5.1, we indicated that, in general, an energy option will provide a day-ahead ancillary service seller with efficient marginal incentives to cover its award (that is, to arrange fuel) when the strike price is set at, or below, its resource's marginal cost of producing energy. To explain why this is the case, some insights from Example 2 will be helpful.

In general, the impact of the strike price on a day-ahead ancillary service seller's incentive to arrange fuel has a nonlinear relationship. Specifically, the incentive, defined as the maximum amount that the generator that sells an energy call option would be willing to spend, is high (and constant) over an initial range of potential strike price levels, and then declines steadily as the strike price rises. At very high strike prices, the incentive may be completely eviscerated. We refer to this as a resource's *incentive profile* curve. For Generator 3 in Example 2 above, its incentive profile curve looks like this:

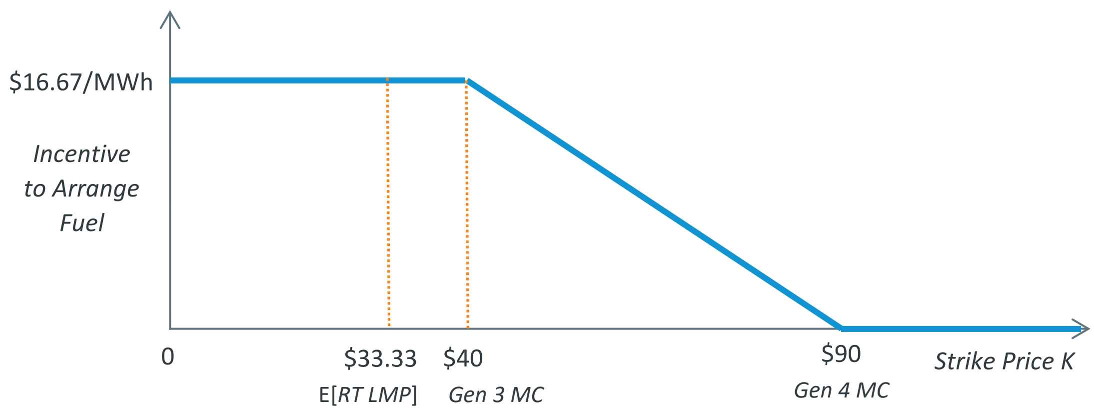

Figure 5-2. Generator 3's Incentive Profile in Example 2

In this graph, the horizontal axis depicts a range of possible strike price values, from zero at the left to higher possible strike price values toward the right. The vertical axis, characterizing its financial incentive, is the maximum amount that the generator that sells an energy call option would be willing to spend, up front, to arrange fuel.[70] (We'll explain the numerical values in Figure 5-2 momentarily.)

[70] A note regarding Figure 5-2: this graph appears similar to, but is substantively different from, textbook diagrams of option payoffs (which also have a flat-then-sloped segment). In textbook diagrams, the strike price is a fixed number and the horizontal axis depicts a varying spot price. In this diagram, the horizontal axis depicts a varying strike price, which is a different analysis.

The incentive inducing a generator to make advance fuel arrangements is maximized on its initial segment, where the curve is flat. If the strike price is set within that range, a seller will fully internalize the impact of its potential non-availability on the real-time LMP. Above a certain level, however, increases in the strike price limit the option's close-out cost if it does not have fuel to operate, and the seller's incentive to arrange fuel for its resource declines.[71] Toward the far right, if the strike price is set far too high, then the close-out charge becomes both *de minimus* and rare (the option is too far "out of the money"). In other words, if the strike price is set too high, the energy option's benefit in incenting fuel becomes zero (for the reasons noted at the start of Guideline 2 in Section 4.5.1).

Next, consider the numerical values shown in Figure 5-2. These will help convey why the strike price is key to achieving efficient marginal incentives for beneficial energy supply arrangements from the system's standpoint.

Recall that in Example 2, we assumed the strike price was $35/MWh. This value falls between the expected value of the real-time LMP, which is $33.33/MWh, and Generator 3's marginal cost of $40/MWh, both shown in Figure 5-2 above.[72]

At the $35/MWh strike price level on the horizontal axis, the $16.67/MWh value shown on the vertical axis represents the maximum cost that Generator 3 would be privately willing to incur to arrange fuel in advance of the operating day. This value is determined by Generator 3's expected option close-out cost if it arranges fuel in advance, versus if it does not. This is evident from Generator 3's settlements in each case:

- From Table 5-4, if Generator 3 has advance fuel, there is a 33% chance it will incur a close-out charge of $100 (see row [4], "high demand" column of Case A).

- In the alternative, if Generator 3 does *not* arrange fuel in advance, then there is a 33% chance of a much higher close-out charge of $1,100 (see row [4], "high demand" column of Case B).

- The expected difference in these market settlement costs for Generator 3 is therefore 33% × [$1,100 – $100] = $333.33 in total. Note that Generator 3's day-ahead ancillary service award is 20 MWh (*see* Table 5-2, row [3]). Therefore, on a per-MWh basis, its expected additional financial consequence in market settlements if it does *not* arrange fuel in advance (relative to if it does) is a charge of $16.67/MWh.

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[71] We simplify slightly. Stated more precisely, above a certain level, increases in the strike price limit the *difference* in the expected value of the seller's option close-out costs if the seller is not able to supply energy in real-time, relative to its (lower) expected close-out cost if it is able to supply energy in real-time.

[72] The expected real-time LMP of $33.33 is equal to the (probability-weighted) average of the three possible energy clearing prices shown in row [6] of Table 2-6 in Section 2.8.1.

This calculation explains why the height of the incentive profile for Generator 3, at a strike price of $35/MWh, is equal to $16.67/MWh in Figure 5-2.[73] One can perform similar calculations for alternative strike prices, using the same settlement calculation logic summarized in Table 5-4 (we omit the details here). For strike prices ranging from $0 up to Generator 3's marginal cost of $40/MWh, the results will be the same: over the region up to the generator's marginal cost, its incentive to arrange fuel is constant, at $16.67/MWh. That is the maximum amount Generator 3 would be willing to spend, up-front, to arrange fuel with a day-ahead ancillary service obligation.

If the strike price is greater than its marginal cost, however, its incentive to arrange fuel declines. In this example, the rate at which its incentive declines is $0.33/MWh for every $1 increase in the strike price above $40. This rate occurs because there is only a 33% (or 0.33) chance that Generator 3's fuel arrangements will impact the real-time LMP (compare the real-time LMPs in row [6] of Tables 5-2 and 5-3, which differ only in the high-demand scenario, which occurs with a 33% chance).

Its incentive becomes zero if the strike price is $90/MWh or above, which is the maximum possible real-time LMP in this example. At a strike price of $90/MWh or more, Generator 3's close-out costs would always be zero if it does not arrange fuel, and it would have no economic incentive to do so since that the fuel is mostly likely not to be needed.

And yet, as we will explain in Section 5.3.2 next, it would be in society's best interest if it did.

► **Implications.** A key insight about the energy option design is that generators will, as a general property, have a flat initial segment of their incentive profile curves for strike prices up to their real-time marginal cost of energy. This region is where its incentives are maximized.

At strike prices above that point, a generator's incentives for energy supply arrangements decline. This too occurs generally. If the strike price is greater than a resource's marginal cost of producing energy, there will be range of real-time energy prices (prices above its marginal cost and below the strike price) for which it would be economic for the resource to operate – *if* it has arranged fuel – but for which the resource will face no option close-out charge if it has not. The absence of financial consequences in this price range diminishes the resource owner's private incentive to arrange fuel in advance of the operating day. And the higher the strike price, the more its incentives diminish.[74]

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[73] For the curious, this result can also be obtained directly using the last row [13] in Table 5-4. There, the difference in Generator 3's expected net revenue with versus without fuel is $37 – (– $147) = $184, which when added to its $150 up-front cost to arrange fuel, is $184 + $150 = $334; on a per-MWh basis, this is $334/20 MWh = $16.7, interpretable (as before) as Generator 3's maximum willingness to spend, up front, to arrange fuel in advance.

[74] In more general settings beyond Example 2, a generators' incentive profile will have a flat segment where its incentive is maximized for strike prices up to (at least) its marginal cost of energy. However, the linear decline above the generator's marginal cost in Figure 5-2 is an artifact of the discrete price outcomes in Example 2; in general, the downward sloping segment above a generator's marginal cost is nonlinear, with a shape determined by the full probability distribution of the real-time price with and without the generator's energy supply. Such technicalities do not change the practical implication that the incentives are maximized when the strike price is set below a resource's marginal cost.

5.3.2 Strike Prices and Efficiency

So far, we have explained why setting the strike price too high – above a resource's marginal cost – will diminish its incentives to arrange energy supplies in advance of the operating day. Will setting the strike at (or below) a resource's marginal cost provide marginal incentives for energy supply arrangements that are cost-effective from society's standpoint? The answer is yes.

To see this, let's first examine the expected benefits (*i.e.,* expected cost savings) from the system's standpoint when Generator 3 arranges fuel in advance, versus when it does not. Table 5-2 reports that the system's total production costs when Generator 3 arranges fuel is $5,233 (*see* row [9]); without rounding, that value is $5,233.33. Table 5-3 reports the system's total production costs when generator 3 does *not* arrange fuel is higher, at $5,400 (*see* row [9]). The difference is the system's expected cost savings, or $5,400.00 – $5,233.33 = $166.67.

Let's convert that into a $-per-MWh basis. Here, the key is to note that if Generator 3 acquires the energy option obligation, but if it does *not* arrange fuel, the *quantity* of energy that must be "replaced" with energy from higher-cost Generator 4 is 10 MWh (*see* Table 5-3, where the cell shaded light orange in row [4] shows 10 MWh for Generator 4's energy, in the high demand scenario). This means that, on a per MWh basis, the system's expected cost savings when Generator 3 arranges fuel in advance, versus when it does not, is $166.67 / 10 MWh = $16.67/MWh.

► **Implications.** The implication of this analysis is important: the flat segment of a resource's incentive profile is where its marginal private incentive to make costly fuel supply arrangements is aligned with the benefit of doing so from society's standpoint. That is, if the strike price is set at (or below) the generator's marginal cost of energy, then it will fully internalize, in its financial calculus, the high cost that prevails if it cannot operate when its generation is in demand.

In Section 5.3.1, we showed that from the perspective of Generator 3's private financial incentive, if its day-ahead ancillary services award has a strike price at or below $40/MWh, then the cost it would be willing to incur to arrange fuel in advance is $16.67/MWh. Then, from the calculations above in this Section 5.3.2, we see that the expected benefit (*i.e.,* expected cost savings) to the system if Generator 3 arranges fuel in advance of the operating day is also $16.67/MWh. In sum, the resource's private incentives to arrange fuel are fully aligned with the system benefits from doing so, as should occur in a sound market design.

The general point is simple. To provide efficient marginal incentives, the strike price should be set at or below a day-ahead ancillary service seller's marginal cost of energy (for the corresponding delivery hour). A strike price that is set higher than that will tend to mute incentives to invest in energy supply (*i.e.,* fuel) arrangements, undermining both the incentives *and* the cost-effectiveness of the new day-ahead ancillary services design.

There are two other important points from this analysis, related to Guidelines 2 and 3 discussed earlier, in Section 4.5. First, if the strike price is set at the expected value of the real-time LMP, then resources that provide ancillary services will tend to be on the flat segments of their incentive profiles – even though the real-time LMP may be below their marginal costs. This will still provide efficient marginal incentives and preserve the cost-effectiveness of the overall design.

Figure 5-2 illustrates this point. There, if Generator 3 arranges fuel, it has a marginal cost of \$40/MWh, and the expected real-time LMP is \$33.33/MWh. A strike price at the expected real-time LMP provides the same incentive to arrange fuel in advance (of \$16.67/MWh) as does a strike price at its marginal cost, because its incentive profile is flat at strike prices below its marginal cost. That is, if Generator 3 acquires an ancillary service obligation for which the ISO sets a strike price at the expected real-time LMP of \$33.33/MWh, the generator would still have efficient incentives to arrange fuel supplies.

While these particular numbers are specific to this example, they illustrate a property that we expect from the markets generally. As discussed earlier, in Section 4.5.1, in the real-time markets, resources that have lower marginal costs than the real-time energy price are committed and dispatched to supply energy. Resources, or portions thereof, that have higher marginal costs than the real-time energy price are designated by the dispatch to supply reserves (provided they have the requisite response and ramping capabilities).[75] For that reason, the desired incentives can be reasonably achieved by setting the strike price at the expected real-time energy price. In doing so, the energy option design will provide much stronger incentives than today for resources to make greater energy supply arrangements to ensure their resources can perform when needed.

The second point to note from this analysis relates to Guideline 3 in Section 4.5.1. There, we noted that small inaccuracies in estimating the expected real-time energy price when setting the strike price should not have large effects, at least within limits. The structure of resources' incentive profiles with energy option awards, as illustrated in Figure 5-2, helps explain why.

Specifically, if the strike price is set too low, that will tend to place more sellers of day-ahead ancillary services on the flat segments of their incentive profile curves. For example, in Figure 5-2, if the strike price is set at (say) \$30/MWh, rather than at the true expected value of the real-time LMP of \$33.33/MWh in this example, then Generator 3 continues to have the same marginal incentive to arrange fuel in advance of the operating day, whenever such arrangements are cost-effective from the system's standpoint. For that reason, a strike price that is set lower than the expected real-time energy price does not weaken the incentives (or efficiency) of the energy option design.

The consequences of setting the strike price too high depend on the magnitudes – thus our point about limits. Using Figure 5-2 again for example, the strike price of \$35/MWh is higher than the expected value of the real-time LMP of \$33.33/MWh, and does not change the generator's incentives – since it remains on the flat segment of its incentive profile, where its incentives are maximized. However, a strike price set (say) \$10/MWh higher than the expected real-time LMP would be \$43.33/MWh and would exceed the generator's marginal cost, and begin to erode its incentives (in this example). In essence, in this example, there is a "margin for error" of

\$40 *marginal cost* – \$33.33 *expected real-time LMP* = \$6.67 / MWh

[75] As noted previously, there are "redispatch" exceptions, but they would not tend to make it efficient to set the strike price *above* the expected real-time LMP. *See* footnote 60 above and accompanying text.

for inaccuracies in the direction of a strike that is too high, before the generator's incentive are affected. Since most generators that provide reserves tend to have marginal costs higher than the real-time energy price, we conclude that small inaccuracies in setting the strike price "at the money" should not matter much – within limits.

5.4 Options on Energy versus Forward Sales of Reserves

As discussed in Section 4, all of the new day-ahead ancillary services – energy imbalance reserve, generation contingency reserve, and replacement energy reserve – will be settled as call options on real-time energy. This means that the day-ahead market will procure options on real-time energy from physical resources; not ancillary services that settle against resources' anticipated real-time reserve designations.

During the stakeholder review process of these Energy Security Improvements, we discussed why this energy option settlement design provides superior incentives to alternative settlement rules that are based on the real-time reserve price. That alternative is most relevant in the context of generation contingency reserves, because the ISO's existing real-time markets presently designate and price real-time reserves for ten-minute and thirty-minute reserve products as well.

In Section 4.3, we explained that the energy option settlement design all works smoothly if day-ahead generation contingency reserve (that is, day-ahead TMSR, TMNSR, and TMOR) awards are settled as call options on energy, and then designated and priced in real-time based on the co-optimized real-time market in use today (*see, e.g*. example (j) in Section 4.3.2). And, as explained in detail in the context of Examples 1 and 2 throughout this Section 5, the real-option design of the day-ahead ancillary service solves the misalignment problem, and would lead resource owners to incur the costs of making energy supply arrangements whenever they would be cost-effective for the system as a whole.

Mechanically, it is also possible to settle day-ahead reserve obligations as deviations against the real-time reserve price, rather than as options on energy. That alternative settlement rule is used in some other ISOs in other regions, though the North American ISOs/RTOs' day-ahead reserve market designs vary greatly.[76] In general, settling day-ahead reserve obligations as deviations against the real-time reserve price, rather than as options on energy, will produce different payments and (very) different incentives, particularly during periods in which fuel supplies may be scarce and energy security concerns are most significant.

In this section, we discuss why resources' incentives to arrange more robust energy supply (*i.e*., fuel) arrangements are superior – *i.e*., more efficient – when day-ahead ancillary service obligations are settled as options on real-time energy, versus a design that settles those obligations as a forward

[76] *See* Energy Security Improvements: Market-Based Approaches, Day-Ahead Reserves - Alternative Settlement Design and its Fuel Security Implications, Presentation to NEPOOL Markets Committee, dated December 10-11, 2019, available at https://www.iso-ne.com/static-assets/documents/2019/12/a6_c_iii_presentation_da_reserves_alternative_settlement_design_fs_implications.pptx, at Slides 11, 42.

sale of real-time reserve designations. The central issue is that when day-ahead obligations for essential reliability services are settled against the reserve price, rather than against the energy price, then sellers will not fully internalize the high price for energy that society pays if fuel is scarce and a resource is unable to operate when needed. As a result, under alternative settlement designs based on the real-time reserve price, a generator's and society's interests remain mis-aligned and the incentives for resources to invest in additional energy supply (*i.e.* fuel) arrangements are significantly muted – particularly when those additional energy supply arrangements would be valued by society the most.

► **Terminology.** In this section, we will compare the incentives that stem from two alternative settlement rules for day-ahead ancillary services. With the energy option design in the Energy Security Improvements, the underlying product is a call option on real-time energy. With a forward reserves alternative design (sometimes called "reserve deviations"), the underlying product is a real-time reserve designation.

Mechanically and economically, the crucial design difference between the two is how the day-ahead ancillary service obligation is settled (or 'close-out'). Specifically:

- With the energy options design, day-ahead reserve awards are closed-out at the real-time energy price less the option strike price, when positive. A resource that is awarded a day-ahead reserve obligation and cannot operate in real-time would be charged in settlement:

  $$\text{DA Ancillary Service Award MWh} \times \max\{0, \mathit{RT\ LMP} - K\}.$$

- With the forward reserve design, day-ahead reserve awards are closed-out at the real-time reserve price (or, equivalently, real-time reserve deviations from day-ahead settle at the real-time reserve price). A resource that is awarded a day-ahead reserve obligation and cannot operate in real-time would be charged in settlement:

  $$\text{DA Ancillary Service Award MWh} \times \mathit{RT\ RCP}$$

  where *RT RCP* denotes the real-time reserve clearing price.

From the standpoint of economic incentives, the energy option settlement rule leads the resource owner to internalize its replacement cost of *energy* in real-time if it does not have fuel to operate. That can be a steep price – and can escalate quickly during stressed conditions if a resource cannot run when needed.

In contrast, the forward reserve settlement rule leads the resource owner to internalize its replacement cost of *reserve* in real-time if it does not have fuel to operate (and, even then, possibly only if it is called for energy, and its failure to have fuel is discovered). That is typically a much less steep price – and does not escalate as quickly, or to as high a level, during stressed condition if a resource cannot run when needed.

To see this most clearly, let us consider each of these two settlement designs in the context of Example 2, as discussed in Section 5.2 above.

► **Application to Example 2.** In Section 5.2.2, we considered Generator 3's decision to incur the up-front \$150 cost to arrange fuel in advance of the operating day under the energy option design. In that example, Generator 3's decision impacts the real-time market only in the high-demand scenario, when its energy is needed to meet real-time energy demand (compare Tables 5-2 and 5-3, right hand columns, in Section 5.2.1).

As we examined in that example, under the energy option design, if Generator 3 does not have fuel (Case B), the real-time LMP in the high demand scenario is \$90/MWh and Generator 3 faces a steep financial consequence in the market settlements, of:

$$-20 \text{ MWh} \times \max\{0, \text{RT LMP} - \text{K}\} = -20 \text{ MWh x} \max\{0, \$90 - \$35\} = -\$1100.$$

(*See* Section 5.2.2). This high-demand scenario has a 33% chance of occurring (Table 5-3, row [8]). Thus, if Generator 3 does not arrange fuel under the energy option design, it faces an expected cost in real-time settlement of

$$33\% \times (-\$1100) = -\$333.33.$$

That expected cost substantially exceeds the up-front \$150 cost of arranging fuel. Thus, it is in Generator 3's private financial interest to arrange fuel – under the energy option design. In effect, Generator 3 is led to fully internalize the \$90/MWh real-time LMP that will prevail (in the high-demand scenario) if it fails to arrange fuel in advance of the operating day.

Now consider the same situation under the alternative, forward reserve settlement design. In Example 2, in the high-demand scenario, the real-time reserve price if Generator 3 does not have fuel (Case B) is \$0/MWh. *See* Table 5-3, row [6], last column. That means if Generator 3 does not have fuel (Case B), when real-time LMP in the high demand scenario is \$90/MWh and the real-time reserve clearing price is \$0/MWh, its financial consequence in the market settlements is:

$$-20 \text{ MWh} \times \text{RT RCP} = -20 \text{ MWh x } \$0 / \text{MWh} = \$0.$$

The high-demand scenario has a 33% chance of occurring (Table 5-3, row [8]). This means that if Generator 3 does not arrange fuel under the alternative reserve settlement design, it faces an expected financial consequence of zero.

Because it faces zero financial consequences if it does not arrange fuel in advance of the operating day, it is not in Generator 3's private financial interest to incur the \$150 up-front cost of arranging fuel – under the alternative reserve settlement design. In effect, nothing in the alternative settlement rule leads Generator 3 to internalize the high \$90/MWh real-time LMP that society will incur (in the high-demand scenario) if it fails to arrange fuel in advance of the operating day. The market's incentives fail.

► **Implications.** The point of this analysis is a general one, and it is important. As shown in Section 5.2.3 and 5.3.2, under the energy option design, resource owners have strong financial incentives to arrange energy supplies in advance, whenever society would benefit from doing so. But, for the reasons indicated in the preceding analysis, under the real-time reserve deviations settlement design, resource owners have far weaker incentives to arrange energy supplies in advance – even though it would be in society's best interest if they did.

At root, the problem here is that the real-time reserve deviations settlement design does not solve the misaligned incentives problem that exists in New England's existing market construct. In this example, the generator is not incented to invest in advance fuel arrangements using the alternative settlement design because the generator's valuation of that investment is based solely on the \$0/MWh real-time reserve settlement charge and the \$40/MWh real-time LMP that it earns when it has fuel and supplies energy in real-time. That is effectively same situation the generator faces today (*see* Section 2.8.2). In contrast, with the energy option design of the Energy Security Improvements, its valuation of the investment is now based on internalizing, in its own financial calculus, the \$90/MWh real-time LMP that society avoids if it makes the investment. And that alignment of incentives does solve the problem.

As noted in Section 5.2.3 earlier, we could create numerous additional examples but they would all demonstrate the same conclusion: the energy option design for the co-optimized day-ahead ancillary services market aligns a resource owner's incentives to invest in energy supply arrangements with the replacement cost that society would incur, at the margin, if it fails to do so. And we have designed the new day-ahead ancillary services as options on real-time energy precisely because of that strong incentive this design creates.

In sum, the incentives for resources to arrange more robust energy supply (*i.e.*, fuel) arrangements are superior – *i.e.*, more efficient – when day-ahead ancillary service obligations are settled as options on real-time energy, versus a design that settles those obligations as a forward sale of real-time reserve designations. For that reason, the energy option design in these Energy Security Improvements is a far preferable improvement to the market design to better address regional fuel security concerns.

6. Energy Imbalance Reserve and the Forecast Energy Requirement

In this section, we provide details on the new Day-Ahead Energy Imbalance Reserve (EIR) ancillary service product. As explained previously, an energy 'gap' arises when resources' total day-ahead energy supply schedules are less than the ISO's load forecast, in one or more hours, during the next (operating) day. Under applicable reliability standards, ISO's operating plan for the next day is intended to ensure there is sufficient energy to cover the forecast load each hour – not simply the level of demand cleared in the day-ahead energy market. This gap is Problem 3 – insufficient day-ahead scheduling – as described in Section 2.

Presently, the energy to cover this gap is supplied through the dispatch and post-market commitment of other resources operating above, or that did not receive, a day-ahead market award. As emphasized in Section 2, however, the existing market construct does not provide these resources with adequate incentives to have energy supply arrangements in place in advance of the operating day – even when it would benefit society if they did.

As explained in this section, with these Energy Security Improvements, the new energy imbalance reserve product will incorporate this reliability service into the day-ahead market. We also explain and provide numerical examples of co-optimized day-ahead market clearing with energy imbalance reserve, in order to illustrate important outcomes and pricing properties.

6.1 Concept And Rationale

As noted in Section 2.6, the ISO relies upon much of the generation fleet's capabilities, above and beyond its day-ahead energy awards, to achieve a reliable next-day operating plan. Under applicable reliability standards, the ISO's operating plan for the next day is intended to ensure there are sufficient (scheduled) resources to cover forecast real-time energy demand.[77] The energy supply needed to cover the system's forecast energy demand for (each hour of) the next operating day is called the system's forecast energy requirement (FER).

In recent years, the day-ahead market's cleared generation and (net) imports has [typically?] been within a few percent of the ISO's forecast of real-time load in most hours. However, even a small gap in percentage terms can amount to many hundreds of MWh (per hour) and frequently over a GWh (*see* Section 6.1.2 below). The ISO relies on resources' capabilities above their day-ahead awards to cover the forecast energy requirement, and may supplementally commit (after the day-ahead market) additional resources for this purpose.[78]

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[77] *See* Brandien Testimony at pp. 6-7, 17-18.

[78] *See* Brandien Testimony at pp. 17-21.

As discussed in Section 2.6, the day-ahead market does not presently compensate the additional resources (or resources' additional capabilities above their day-ahead energy awards) that the ISO relies upon to cover this energy gap. As highlighted in Section 2.7, this state of affairs contributes to the ISO's concerns over energy security. Specifically, and as Examples 1 and 2 in Section 2 showed, resources (or portions thereof) that do not receive a day-ahead market energy supply obligation may not find it financially prudent to make costly energy supply arrangements in advance of the operating day. This not only can result in a failure of the markets to promote cost-effective investments in energy supply arrangements, it can place the power system at heightened reliability risk.[79]

6.1.1 Integrating the Forecast Energy Requirement into the Day-Ahead Market

To address this concern, the Energy Security Improvements integrate the system's hourly forecast energy requirement into the co-optimized day-ahead energy and ancillary service market.

At a conceptual level, the idea is simple. The day-ahead market will continue to clear market participants' submitted offers to supply, and bids to buy, energy day-ahead. When the total cleared energy from the system's physical supply resources is less than that hour's forecast energy requirement, the co-optimized day-ahead market will now procure energy options from additional resources (or from resources' additional capabilities above their day-ahead energy schedules), to cover that energy gap.

The energy call options procured for this purpose will receive Day-Ahead Energy Imbalance Reserve Obligations, and be settled consistent with the standard energy option settlements described earlier, in Section 4. The total amount of energy imbalance reserve procured will be (just) sufficient to 'fill the gap' between physical supply resources' total day-ahead market energy awards and the system's forecast energy requirement.

► **Simple examples.** A few simple examples are useful to illustrate the new energy imbalance reserve product. In each case below, consider a single hour of the day-ahead market, and assume the system's forecast energy requirement is 20 GWh for the applicable hour.

a) Total cleared energy demand in the day-ahead market is 18 GWh, all of which is cleared against energy supply offers from physical resources (*e.g.,* generation and imports). The day-ahead market also clears 2 GWh of energy imbalance reserve from resources that offered energy call options.

   In this situation, the day-ahead cleared energy from physical supply resources of 18 GWh is less than the forecast energy requirement of 20 GWh. However, with the additional 2 GWh of energy imbalance reserve, the combined energy and energy imbalance reserve cover the systems' forecast energy requirement:

[79] *See* example 1-R in Section 2.2.2; *see also* Brandien Testimony at pp. 23-26.

18 GWh of energy + 2 GWh of EIR ≥ 20 GWh forecast energy requirement.

b) Similarly, imagine instead cleared energy in the day-ahead market is 19 GWh, all from physical supply resources, and cleared energy imbalance reserve is 1 GWh. The combined energy and energy imbalance reserve again covers the forecast energy requirement:

19 GWh of energy + 1 GWh of EIR ≥ 20 GWh forecast energy requirement.

What if total cleared energy from physical supply resources is greater than the forecast energy requirement? Then the day-ahead market's demand for energy imbalance reserve will be zero.

c) Suppose now that total cleared energy from physical supply resources is 21 GWh. This exceeds the forecast energy requirement of 20 GWh, so no energy imbalance reserve is needed:

21 GWh of energy + 0 GWh of EIR ≥ 20 GWh forecast energy requirement.

In this case (c), there is no 'energy gap' between the day-ahead market's cleared physical supplies and the system's forecast demand for energy in real-time.

Case (c) illustrates an important observation. Since energy imbalance reserve is procured from suppliers at a price, the co-optimized day-ahead market will procure it only to the extent necessary to close the energy gap to the forecast energy requirement. If sufficient energy clears economically from physical supply resources to cover the forecast energy requirement for a particular hour of the next operating day, the amount of energy imbalance reserve cleared for that hour will be zero.

► **Other energy gap factors.** In examples (a) and (b), the energy gap that is covered by energy imbalance reserve arises because the total cleared day-ahead energy demand is less than the forecast energy requirement. That is one cause of an energy gap. However, there is another mechanism by which a need for energy imbalance reserve can arise. A portion of day-ahead energy demand may clear not against supply offers from physical resources, but against "virtual" energy supply offers in the day-ahead energy market. (In the Tariff, virtual energy supply offers are called Increment Offers).

As context, virtual supply offers are financial offers in the day-ahead market that, if cleared, are closed-out at the real-time energy price; we say they are "financial" in the specific sense that a virtual supply offer is not associated with a physical resource, and therefore does not supply energy in real time. For that reason, only energy supply offers cleared in the day-ahead market from physical supply resources (*e.g.,* generation and imports) are counted toward the system's forecast energy requirement for the next operating day.

Virtual transactions have a useful role in increasing the competitiveness of the day-ahead energy market.[80] However, when virtual supply offers clear, under certain conditions they may contribute to the energy gap between the day-ahead market and the forecast energy requirement. When this occurs under the co-optimized day-ahead market design, energy imbalance reserve will fill that gap as well. Here is a simple example.

d) Total cleared energy demand in the day-ahead market is 20 GWh, matching the system's forecast energy requirement of 20 GWh. On the supply side, the day-ahead market clears 19 GWh from physical supply resources and 1 GWh from virtual supply offers. In this situation, total demand matches supply in the day-ahead market's clearing, but there is an 'energy gap' of 1 GWh between the day-ahead cleared energy from physical supply resources (at 19 GWh) and the forecast energy requirement for real-time operations (at 20 GWh).

   Now assume the day-ahead market also clears 1 GWh of energy imbalance reserve from additional supply resources that offered energy call options.

   In this situation, with the additional 1 GWh of energy imbalance reserve, the combined energy and energy imbalance reserve cover the systems' forecast energy requirement:

	19	GWh of energy from physical supply resources
+	1	GWh of EIR from physical supply resources
≥	20	GWh forecast energy requirement.

Cases (a) through (d) illustrate two situations in which the current day-ahead energy-only market may produce a gap between the total energy cleared from physical supply resources and the system's forecast energy requirement for real-time operations. One is when total day-ahead cleared energy demand is less than the forecast energy requirement. The second may occur if virtual supply offers competitively displace the clearing of physical supply resources, as occurs in case (d). In that situation, even if cleared energy demand meets or exceeds the forecast, virtual supply contributes to an energy gap if the remaining cleared supply offers (from physical resources) are less than the forecast energy requirement.[81]

The co-optimized day-ahead market is designed to address both energy gap situations, using a single new ancillary service: Day-Ahead Energy Imbalance Reserve. This is important because both situations can (and do) occur concurrently. Accounting for both situations, an analysis of data from

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[80] For a detailed discussion of virtual transaction and their role in the day-ahead market, *see* 2018 Annual Markets Report, dated May 23, 2019, available at https://www.iso-ne.com/static-assets/documents/2019/05/2018-annual-markets-report.pdf, at pp. 119-126.

[81] Cleared virtual transactions have increased steadily over the last five years; in 2018, average cleared virtual supply was 621 MWh per hour. *Id*. at p. 124.

2018 indicates that there was an energy gap between the day-ahead energy market's outcomes and the forecast energy requirement in more than 78 percent of all hours (*see* Section 6.1.2, next).[82]

► **Implications.** Before proceeding to more detailed examples, we highlight two summary points here. First, viewed from the standpoint of the broader architecture of markets and reliability, we are bringing the existing forecast energy requirement into the day-ahead market. In doing so, satisfying the forecast energy requirement will now become a market process, not an out-of-market process conducted after the day-ahead market.[83] That effort has the additional benefit of improving price formation by enabling the markets to better signal, through transparent prices, the costs incurred to achieve a reliable next-day operating plan that covers forecast real-time energy demand.

The second point is that, viewed from an economic perspective, the energy option construct is naturally suited to this purpose. As noted above, the ISO's current practices rely on resources' capabilities (that are not compensated in the day-ahead market) to help cover forecast energy demand. But, beyond the energy supply scheduled in the day-ahead market, the ISO does not compensate resources on a day-ahead timeframe for the ISO's option to call on them after the day-ahead market. The ISO effectively pays a 'price' of zero for that option in today's day-ahead market today – but that option isn't actually free. Rather, providing that option to the system is costly for generators, particularly if they must incur costs to make fuel supply arrangements in advance of the operating day to ensure they can perform.

With the energy imbalance reserve component of the Energy Security Improvements, the ISO's markets will now price properly, transparently, and competitively, this currently unpriced (indeed, currently *mis*priced) option value. And, by using the standard option-based settlement design for Day-Ahead Energy Imbalance Reserve Obligations, the new design resolves the misaligned incentive problem for these resources – providing new compensation, and incentives, to undertake stronger energy supply arrangements to ensure reliable power system operations.

6.1.2 The Day-Ahead Market's Energy Gap Is Recurring Event

In the day-ahead market today, the energy gap is a common event. However, its magnitude can vary significantly from day to day, and hour to hour. Figure 6-1 shows the energy gap between the day-ahead load forecast and the total energy cleared from all physical supply resources in the day-ahead market, for each hour of 2018.[84]

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[82] *See also* Brandien Testimony at pp. 21-22.

[83] The ISO's existing process for this purpose is described in Brandien Testimony at pp. 17-23.

[84] In these data, the load forecast is the ISO's final next-day forecast of total electricity demand for each hour of the next day for the New England Balancing Authority Area, net of distributed generation. Day-ahead cleared energy from all physical supply resources is the sum total MWh cleared in the day-ahead market for the corresponding hour from: (1) all generating assets, (2) all active Demand Response Resources, and (3) the net interchange MWh over all external interfaces scheduled in the day-ahead market from other Balancing Authorities into New England (New England is a net importer of electricity). For additional discussion, *see* Section 6.4.1.

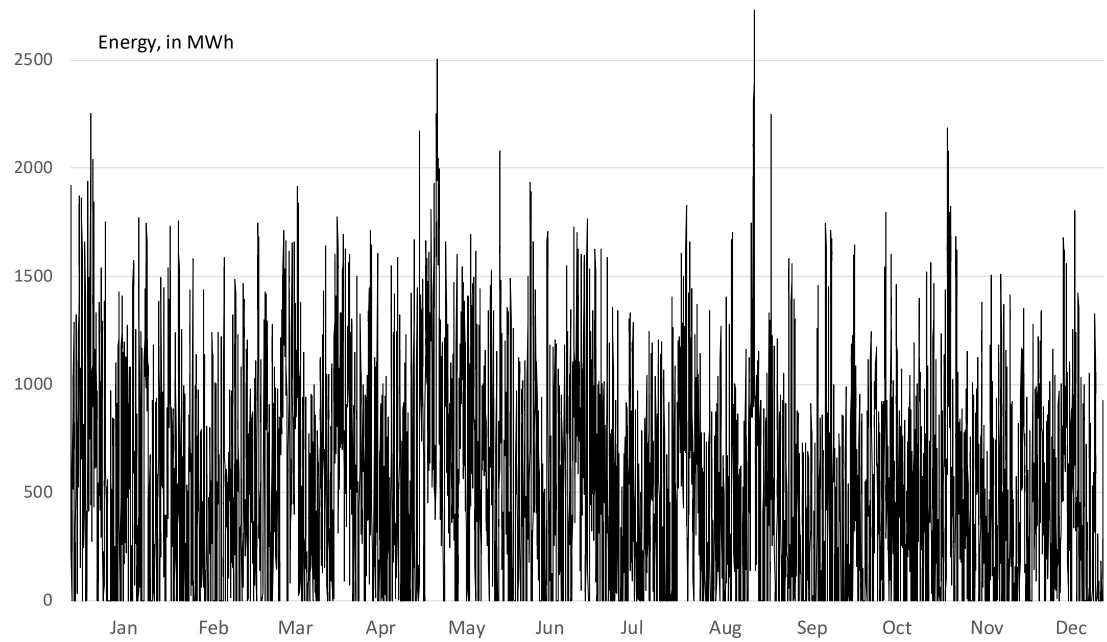

Figure 6-1. Hourly Day-Ahead Market Energy Gap, 2018

The figure shows frequent and often large energy gaps occurring throughout the course of the year. Overall, in 2018, the energy gap was zero in only 22 percent of hours, and the median hourly value was 459 MWh. It exceeded 1,000 MWh in over 25 percent of all hours (nearly 2200 hours in total in 2018). The hourly maximum of 2,728 MWh occurred on September 3, 2018, and the system experienced a real-time shortage of operating reserves for several hours that afternoon.[85]

In 2019, the energy gap pattern was qualitatively similar to that in 2018 as shown in Figure 6-1. The overall magnitudes were generally lower, with a median hourly value of 194 MWh and an energy gap of zero in a slightly larger proportion of the year, 35 percent of all hours. While the full reasons for the slightly more frequent and higher median hourly energy gaps in 2018 are not entirely clear, we do not infer a trend from these two years' of data.[86]

These recent data highlight two important observations. First, the energy gap is a recurring, persistent daily phenomenon in New England's day-ahead energy market. Second, the magnitude of the energy gap is not constant from day to day or hour to hour, and the mechanism designed to fill it must be commensurately flexible and dynamic.

[85] For discussion of that event, *see* Brandien Testimony at pp. 22-23.

[86] In particular, the differences between 2018 and 2019 may be because 2019 was a markedly milder weather year in New England than 2018 (both summer and winter), with lower electricity demand and supply levels overall.

6.2 Day-Ahead Clearing and Pricing with Energy And Energy Imbalance Reserve: Two Supply and Demand Curves

It is important that the quantity of energy and of energy imbalance reserve cleared in the day-ahead market be jointly (*i.e.,* simultaneously) determined in a co-optimized clearing process. That is crucial to efficient pricing and to economical market outcomes. The co-optimized clearing of energy and energy imbalance reserve has important pricing and compensation implications, which merit detailed discussion next.

Fortunately, the economic logic of how the day-ahead market will clear with co-optimized energy and energy imbalance reserve can be readily visualized. We'll consider first the outcomes of the day-ahead energy-only market of today, using simple concepts of supply and demand. Then, we'll incorporate the forecast energy requirement as a 'second' demand curve into the analysis, and explore the beneficial outcomes that result.

6.2.1 Day-Ahead Market Clearing Today: Energy Only

At a broad level, day-ahead market outcomes today can be visualized as a textbook supply and demand diagram. *See* Figure 6-2. The upward-sloping line represents the market-level energy supply curve, comprised of all sellers' energy supply offers. The downward-sloping line represents the market-level energy demand curve, comprised of all participants' bids-to-buy energy day-ahead.

To simplify, in this example we will ignore the role of virtual supply in order to focus first on the situation when cleared energy demand is less than the forecast energy requirement. (We address the role of virtual supply in detail in Section 6.5). Mechanically, that means we will assume all of the energy offers in the supply curve in this figure and the next are from physical supply resources (*e.g.,* generation or imports). We also ignore here day-ahead transmission congestion and energy losses, which would unnecessarily complicate explanations; their inclusion would not change the logic and conclusions reached here.

An efficiently-organized market clears where marginal benefit equals marginal cost. In this classic supply and demand diagram, that occurs at the quantity *D* in Figure 6-2. Marginal benefit is measured by the maximum amount that buyers are willing to pay for another MWh, which is the vertical 'height' of the demand curve at quantity *D.* This is equal to the marginal supply offer price, which is the vertical 'height' of the supply curve at quantity *D.* The market clearing price is equal to the value of *DA LMP,* where marginal benefit from serving demand equals the marginal cost of serving demand.[87]

[87] Throughout this section we assume competitive supply conditions in which sellers' offer prices reflect their marginal costs.

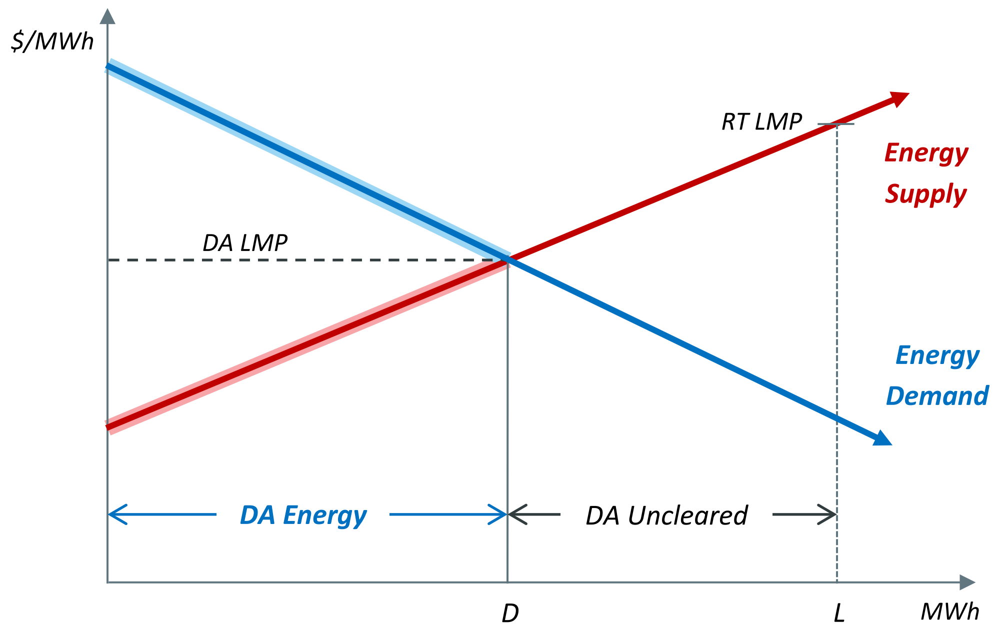

Figure 6-2. Day-Ahead Market Clearing with Energy Only

Here it is useful to note two points in relation to the energy gap concerns summarized in Section 6.1. First, in Figure 6-2 we have also added a forecast real-time load level at the quantity denoted by *L,* and assumed this is greater than total day-ahead cleared energy at *D*.[88] The difference between *L* and *D* represents the energy gap that we have been discussing. Second, the supply resources (or portions of supply resources) needed to cover that energy gap have no day-ahead market obligation. This is represented by the MWh range denoted "DA Uncleared" between *D* and *L* along the horizontal axis in Figure 6-2.

We next consider how the market outcomes change when we add to these same supply and demand curves a forecast energy requirement in order to close that energy gap.

6.2.2 Day-Ahead Market Clearing with Energy Imbalance Reserve

Conceptually, integrating the forecast energy requirement into the day-ahead market means there are, in effect, *two* demand curves. One is participants' aggregate demand curve , comprised of their submitted bids to buy energy day-ahead. The second is the forecast energy requirement. (The

[88] Because of this energy gap, the day-ahead LMP is also less than the expected real-time LMP in this example. In Figure 6-2, the expected real-time LMP is where the supply curve intersects the forecast energy demand at *L*.

second requirement is a quantity, or "vertical" demand level, and not literally a "curve"; with that proviso, we will nonetheless refer to it as a demand curve).

When there are two demand curves, there will be two cleared quantities. One quantity is for cleared energy. The second, *additional* quantity, will be energy imbalance reserve. The two, in sum, will satisfy (that is, equal or exceed) the forecast energy requirement.

Importantly, when there are two demand curves, there will also be two clearing prices. One price will reflect the bid-in demand for energy, and set the LMP. The second price will reflect the *incremental* cost of the forecast energy requirement. We call that second price, naturally, the Forecast Energy Requirement Price (abbreviated in figures as the "FERP").

► **Energy imbalance reserve supply curve**. Figure 6-3 depicts the market clearing outcomes with the forecast energy requirement, for the same participant-submitted energy supply and demand conditions shown in previous Figure 6-2.[89] As before, the forecast energy requirement is shown by the vertical line at quantity *L.*

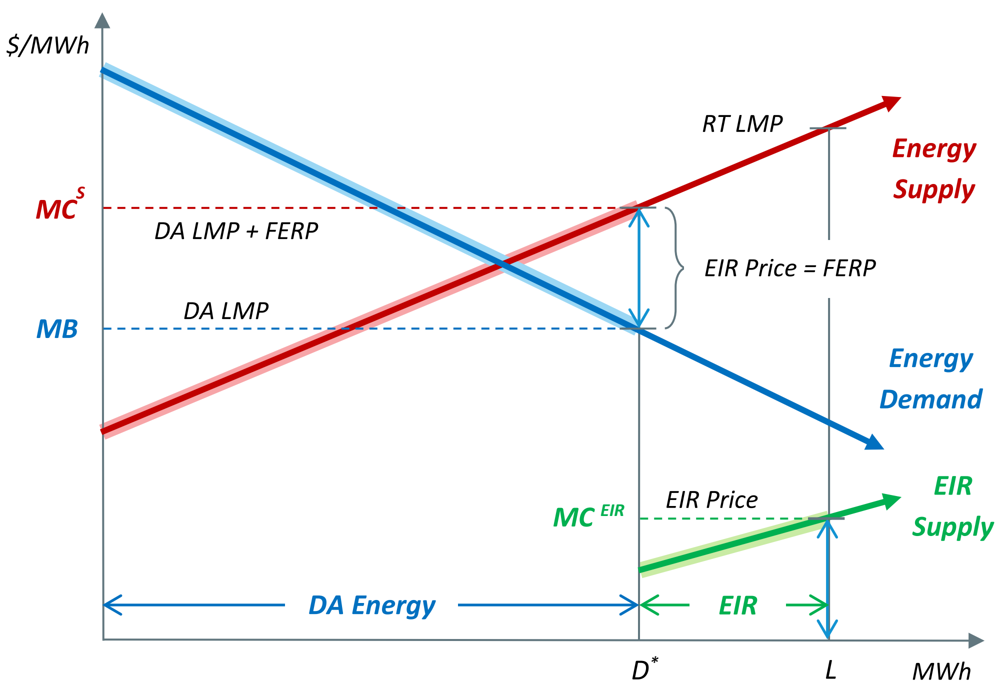

Figure 6-3. Day-Ahead Market Clearing with the Forecast Energy Requirement

[89] Specifically, Figure 6-3 similarly assumes all energy supply offers are from only physical supply resources (*e.g.,* generation or imports), not "virtual" supply, and ignores day-ahead transmission congestion and energy losses.

In Figure 6-3 we have now added a new supply curve of energy option offers that may be cleared as energy imbalance reserve. This supply curve is shown in the green in Figure 6-3, and appears below the energy supply and demand curves. In Figure 6-3, please note that the aggregate option offer supply curve is drawn starting from point *D*,* where the option supply curve indicates the offer price of the first (lowest-priced) option offer*,* and then ascends upward as we move right to the forecast energy requirement at *L.* The reason for this graphical location of the option offer supply curve will be clear momentarily.[90]

As in the simple examples in Section 6.1, a co-optimized market will clear so that the sum of physical energy supply and energy imbalance reserve satisfies the forecast energy requirement, at *L.* We'll first explain why, with the same participants' supply and demand curves for energy, the market now clears the mix of energy and energy imbalance reserve shown in Figure 6-3: quantity *D** of energy, and quantity (*L – D**) of energy imbalance reserve. This is a greater quantity of energy than clears in the market without a forecast energy requirement, which was amount *D* in Figure 6-2.

► **Clearing Quantities**. Here and generally, an efficient market clearing aligns marginal benefit and marginal cost. With two types of supply offers (for energy and for energy options), however, there are now two different marginal costs to consider.

First, there is the marginal cost of the supplier that is at the margin for energy. In Figure 6-3, this is the value (height) of the energy supply curve at the quantity *D*.* On the left axis we have labeled this cost as MC^S, for *marginal cost of energy supply*.

Second, there is the marginal cost of energy imbalance reserve, from the supplier that is at the margin for energy imbalance reserve. In Figure 6-3, this is the value (height) of the energy imbalance reserve supply curve at the quantity *L.* We have labeled this as MC^{EIR}, for *marginal cost of EIR*.

Now, the crux. What is the marginal cost to serve another increment of bid-in energy demand in the day-ahead market? With two supply curves, this involves the two products' marginal costs – or, rather, the *difference* between their marginal costs. To see this, observe that if market participants demanded (procured) an additional 1 MWh of energy, then the remaining energy gap to be procured as energy imbalance reserve would be *1 MWh less.* This is because the sum of cleared energy and cleared energy imbalance reserve must still equal the (same) forecast energy requirement, *L.*

In economic terms, this means that with a forecast energy requirement, there is a cost savings to account for when additional energy is purchased in the day-ahead market. The true marginal cost of serving one more MWh of energy demand is equal to the marginal cost of one more MWh of energy supply (from the marginal resource on the energy supply curve), *less* the cost that is saved because the market will procure one *less* MWh of energy imbalance reserve. That is, the marginal cost of

[90] A technical note: in Figure 6-3, we assume the supply curves do not 'double count' the same MW of a resource's capability in both the energy supply curve and energy imbalance reserve supply curve. This is enforced in the market clearing process, but difficult to show visually.

serving energy demand is the difference between the marginal cost of energy supply and the marginal cost of energy imbalance reserve:

(♦) *MC of serving energy demand = MC of energy supply – MC of EIR*

That relationship is key to explaining the quantity of energy and energy imbalance reserve that the market will clear. As always, an efficient market will clear where the marginal benefit equals the marginal cost of serving energy demand, or:

MB of serving energy demand = MC of serving energy demand

In evaluating the right-hand side of that expression, however, the market's clearing must account for both the marginal cost of energy supply as well as the (marginal) cost savings from the reduction in energy imbalance reserve, according to equation (♦).

In Figure 6-3, the quantity of energy where this occurs is at *D*.* There, the marginal benefit of energy demand is equal to the vertical 'height' of the energy demand curve at *D*.* We've labeled this value on the left axis as *MB* (for marginal benefit, naturally). The vertical distance *between* market participants' energy supply and demand curves at the market-clearing quantity, *D*,* is important: it is equal to the marginal cost of energy imbalance reserve, MC^{EIR}, that is saved by procuring the last unit of energy demanded (using again equation (♦)).[91]

Put simply, when there are two demand curves and two supply curves, the efficient market outcome is not where the supply and demand curves for energy *alone* intersect one another. Rather, the efficient market outcome must also account for the fact that clearing an additional MWh of energy *reduces* the amount of EIR that must be cleared to cover the forecast energy requirement. This trade-off between energy and energy imbalance reserve occurs whenever energy supply and bid-in energy demand intersect to the left of (that is, at a quantity below) the forecast energy requirement, which creates an energy gap for energy imbalance reserve to fill. As Figure 6-3 shows, in these conditions, the co-optimized day-ahead market will now clear a *greater* amount of energy than the energy-only day-ahead market of today – using both this additional cleared energy, as well as cleared energy imbalance reserve, to close that 'gap' and meet to the forecast energy requirement.[92]

Let's consider some broader implications of that important insight about the co-optimized day-ahead market's outcomes. We'll then explain the corresponding market prices.

► **Implications**. Equation (♦) has a powerful economic implication. It implies that, when the system clears energy imbalance reserve, the marginal cost of serving bid-in energy demand is *less*

[91] In practice, these marginal costs are calculated using the supply offer prices of the marginal resources for each product (energy and for energy imbalance reserve), evaluated at the system's market-clearing quantities.

[92] Note that if energy supply from physical resources and the energy demand curve intersect to the right of (that is, at a quantity greater than) the forecast energy requirement, then the forecast energy requirement would already be met and zero energy imbalance reserve would be cleared. (*See* simple example (c) in Section 6.1).

than the marginal resource's energy supply offer. That lower marginal cost of serving energy demand means the day-ahead market will clear more energy with a forecast energy requirement, relative to today's energy-only day-ahead market.

Viewed from a broader market and reliability perspective, that fact has three benefits. First, the day-ahead market's energy schedules for supply resources will now be closer to what we expect in real-time during the next operating day. In general, the closer that the next-day operating plan matches what resources are called upon to produce during the next operating day, the more reliable the system tends to be.

Second, more *energy* from supply resources has cleared, in an amount (in MWh) equal to the horizontal distance ($D^* - D$) between Figures 6-1 and 6-2. The supply resources in that range of the supply curve (that is, between D and D^*) now clear energy in the day-ahead market, can expect to operate the next day, and will receive day-ahead compensation with which to arrange fuel in advance of the operating day.

Third, the combined total energy and energy imbalance reserve that is cleared (in MWh) in the co-optimized day-ahead market is sufficient to satisfy the forecast energy requirement. The resources that now cover the 'gap' between cleared energy and the forecast energy requirement have a Day-Ahead Energy Imbalance Reserve Obligation, consistent with the energy option settlement design. For all of the reasons explained in Sections 4 and 5, those resources now have stronger incentives to arrange fuel to ensure they can operate the next day.

In sum, by bringing the forecast energy requirement into the day-ahead market clearing process, the energy supply and energy imbalance reserve obligations now cover the forecast energy requirement. The system achieves a next-day operating plan that satisfies the forecast energy requirement through the day-ahead market alone – not through an unpriced, "out of market" process after the day-ahead energy market is conducted. And, most importantly, we will now compensate resources – both those that provide energy and that provide energy imbalance reserve – through transparent, competitively-determined market prices that reflect the cost of satisfying the forecast energy requirement for the next operating day.

In doing so, the market will compensate resource owners for the energy imbalance reserve capabilities that previously filled this energy gap but were not compensated day-ahead. They will be compensated for their intrinsic *option value* – that is, the value of the ISO's ability to call upon their energy during the operating day to meet real-time demand. And, since that option value compensation comes with proper energy call option settlements, it resolves the fundamental misaligned incentives problem for those resources.

6.2.3 Day-Ahead Clearing Prices

We now consider the day-ahead market's pricing with a forecast energy requirement and energy imbalance reserve, and who gets paid what. First, we'll explain the mechanics of the clearing prices shown in Figure 6-3. Then we'll consider more closely why these are the economically-appropriate market price signals, and assess their implications.

As the previous discussion indicated, market prices with a forecast energy requirement and energy imbalance reserve reflect marginal-cost pricing principles. The pricing consideration to account for is the presence of two demand curves and two supply curves.

With two demand curves and two supply curves, there will be two distinct market clearing prices. Both prices reflect marginal costs. The market clearing price for energy reflects the marginal cost to serve energy demand. That determines the day-ahead LMP. The second price reflects the *incremental* cost of the forecast energy requirement. That determines the Forecast Energy Requirement Price.

► **The day-ahead LMP.** The economic logic of the day-ahead LMP is based on the same marginal cost considerations that determine the market-clearing quantities. As noted earlier, if market participants demanded (procured) an additional 1 MWh of energy, then the remaining energy 'gap' to be procured as energy imbalance reserve would be 1 MWh less. This means that the marginal cost to serve energy demand is determined by the marginal cost of the energy supplied, *less* the marginal cost saved by procuring less energy imbalance reserve (see again equation (♦) above). The marginal cost to serve energy demand determines the day-ahead LMP, so the day-ahead LMP is

$$\textit{DA LMP} = \textit{MC of energy supply} - \textit{MC of EIR}$$

whenever the market clears energy imbalance reserve.[93] In Figure 6-3, the day-ahead LMP is where the demand curve for energy reaches the market clearing quantity for energy at *D**. This price is labeled *DA LMP* in the graph.

From an economic perspective, the day-ahead LMP represents the marginal benefit of energy to buyers (denoted *MB* on the left-axis in Figure 6-3). This is the economically-correct price signal to demand – it ensures that all cleared demand bids for energy are willing to pay the day-ahead LMP for energy, and that demand bids not cleared for energy are not willing to pay that price. Equally importantly, it enables the LMP for energy in the day-ahead market to properly signal the system's marginal cost of serving that demand. It does so by accounting for both the marginal cost of energy supply (as does the LMP today), and now accounting for the concurrent cost reduction in energy imbalance reserve to satisfy the forecast energy requirement.

Two additional observations merit note. First, if there is transmission congestion in the day-ahead market, then the marginal cost to serve another increment of energy demand will vary by location, and therefore so will the day-ahead LMPs. The marginal cost of energy imbalance reserve does not vary by location, as that is a system-level product with the same marginal cost (and the same energy imbalance reserve price) system-wide.[94]

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[93] This pricing logic applies when there is some energy imbalance reserve to be "saved" by clearing more energy; that is, it holds when the market clears a positive quantity of energy imbalance reserve (in MWh).

[94] In practice, the ISO calculates day-ahead LMPs based on the shadow price of the energy supply-equals-demand constraint at the cleared quantity of energy *D** (*see* the market clearing requirement expression in Section 6.4.1 below.) This enables the prices to account for energy losses, transmission limits, and additional reserve constraints (discussed in

Second, in the analysis so far and as depicted in Figure 6-3, we have assumed that participants' energy supply and demand curves intersect to the left of (that is, at a quantity less than) the forecast energy requirement. However, sometimes the market clears more energy from physical supply resources than the forecast energy requirement.[95] In such cases, from an economic perspective, the intersection of participants' demand curve and the supply curve of energy (from physical resources) would be to the right of (that is, at a quantity strictly greater than) the forecast energy requirement. When that occurs in the co-optimized day-ahead market, pricing simplifies: the day-ahead LMP would be set where participants' energy supply and demand intersect, as occurs today. The quantity of energy imbalance reserve cleared would be zero, as would be the price of energy imbalance reserve, as the forecast energy requirement is already satisfied without it.

► **The forecast energy requirement price and the energy imbalance reserve price.** As noted above, with two demand curves and two supply curves, there will be two distinct market clearing prices (with an emphasis on 'distinct'). The day-ahead LMP reflects the marginal cost to serve energy demand. Similarly, the Forecast Energy Requirement Price reflects the marginal cost to satisfy the forecast energy requirement. The third price concept we will explain, the energy imbalance reserve price, is equal to the Forecast Energy Requirement Price and is not a separate settlement rate.

First, consider the Forecast Energy Requirement Price. Following marginal pricing principles, this price is the marginal cost to satisfy an increase in the forecast energy requirement (that is, an incremental MWh above the quantity *L* in Figure 6-3). Since another increment of energy imbalance reserve can (always) be used to satisfy an increase in the forecast energy requirement, this marginal cost must equal the marginal cost of energy imbalance reserve. Thus, in Figure 6-3 and more generally, the Forecast Energy Requirement Price is equal to the energy imbalance reserve price.

Next, following the same marginal pricing principles, the energy imbalance reserve price is determined by its marginal cost at the market-clearing quantity of energy imbalance reserve. In Figure 6-3, the market-clearing quantity of energy imbalance reserve is ($L – D^*$). (Recall that in Figure 6-3, the supply curve for energy imbalance reserve is shown starting from D^*.) The energy imbalance reserve price is set where the supply curve of energy options cleared for energy imbalance reserve reaches the market clearing quantity, ($L – D^*$). This is labeled the *EIR Price* in Figure 6-3, and is equivalent to MC^{EIR}.

Note that since the Forecast Energy Requirement Price and the energy imbalance reserve price are equal (here and always), they do not represent distinct payment rates – they have the same numerical value. We use both terms for expositional purposes, here and in the Tariff, because they are paid to different cleared quantities and products (the Forecast Energy Requirement Price is paid to cleared energy supply, while the energy imbalance reserve price is paid to cleared energy

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later sections) that for simplicity we have omitted from Figures 6-2 and 6-3. Those technical calculation methods reflect the economic logic here.

[95] This occurred in 22 percent of all hours in 2018, and in 35 percent of all hours in 2019. *See* Section 6.1.2.

imbalance reserve); the terminology helps to keep clear which resources receive which payments in the mechanics of settlement charges and credits (more about which below).

Crucially, the sum of the day-ahead LMP and the Forecast Energy Requirement Price is equal to the marginal cost of energy supply. In Figure 6-3, the Forecast Energy Requirement Price is labeled *FERP* and is the vertical distance *between* the day-ahead LMP and the energy supply curve (*i.e.,* the marginal cost of energy supply) at the market-clearing quantity of energy *D**. Stated as a formula:

$$\textit{MC of energy supply} = \textit{DA LMP} + \textit{FERP}.$$

In this way, the co-optimized market with energy and energy imbalance reserve now delineates – that is, it separately prices – the system's marginal cost of energy supply into two distinct price signals: the marginal cost of serving day-ahead energy demand (the day-ahead LMP), and the *additional* marginal cost to satisfy the forecast energy requirement (the Forecast Energy Requirement Price, *FERP*).

Importantly, and as discussed in detail next, energy suppliers will continue to be compensated based on the marginal cost of energy supply. Specifically, in today's energy-only day-ahead market, sellers' payment rate for energy reflects the system's marginal cost of energy supply (*see* Figure 6-2). Similarly, in the co-optimized market, sellers' payment rate for energy will also reflect the marginal cost of energy supply (*see* Figure 6-3). The numerical value of that payment rate will now have two components: the day-ahead LMP *and* the forecast energy requirement price. Critically, however, the fundamental economic logic of compensating energy suppliers based on the marginal cost of energy supply has not changed at all.[96]

► **Who gets paid what?** These market prices determine the payment rates applicable for energy and energy imbalance reserve in the co-optimized day-ahead energy market. We summarize the payments here, and then explain why they provide the economically appropriate compensation levels next.

- *First*, each MWh of energy demand that is cleared in the day-ahead market pays its day-ahead LMP. In this way, buyers' payment rate for energy reflects both the marginal benefit of energy, and the system's marginal cost of serving energy demand.

- *Second*, each MWh of physical energy supply that is cleared in the day-ahead market is paid the *sum* of its day-ahead LMP and the Forecast Energy Requirement Price.[97] In this way, the rate that sellers are paid for energy will continue reflect the marginal cost of energy supply, as it does today.

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[96] A caveat: though these pricing concepts apply similarly to "virtual" supply ("Increment") offers in the day-ahead energy market, the exact formulas do not. *See* Section 6.5

[97] A virtual supply (or "Increment") offer that clears in the day-ahead market will be paid the day-ahead LMP as is the case today, but is not paid the Forecast Energy Requirement Price because it has no physical energy supply to contribute to the forecast energy requirement for the next operating day. For details, *see* Section 6.5.

- *Third,* each MWh of energy call options that is cleared in the day-ahead market as energy imbalance reserve is paid the energy imbalance reserve price (which, again, is equal to the Forecast Energy Requirement Price). In this way, sellers' payment rate for energy imbalance reserve will reflect the marginal cost of its supply.

These pricing and compensation rules produce the economically appropriate price signals and payment rates, as discussed presently.

Last, the costs of satisfying the forecast energy requirement must be allocated. The cost of the Forecast Energy Requirement Price paid to energy suppliers in the day-ahead market is allocated (primarily) to real-time energy demand, on the beneficiary-pays principle. The cost of day-ahead energy imbalance reserve price paid to suppliers is allocated (primarily) to the market participants whose real-time deviations from their day-ahead energy schedules are covered by energy imbalance reserve, on cost-causation principles. We discuss these cost-allocation rules, and their rationale, in detail in Section 6.6.

► **The co-optimized day-ahead market produces economically appropriate prices and payments.** When there are multiple products in a market, there are three economic pricing principles that come into play. It is useful to summarize each of these principles, and how they are satisfied by the co-optimized day-ahead market's prices and payment rates.

The marginal-cost pricing principle. The day-ahead market's prices and payments all reflect the principle of marginal-cost pricing in efficient markets. As explained above, energy supply is compensated based on the marginal cost of energy supply; energy demand is charged based on the marginal cost of serving energy demand; and energy imbalance reserve supply is compensated based on the marginal cost of energy imbalance reserve.

***The participation payment principle*.** This principle guides compensation in a multi-product market when a participant's single offer satisfies multiple market demands or requirements. It provides that, in an efficient market, an offer that participates in satisfying multiple requirements should be paid the price associated with *each* requirement. In this way, the participating offer is compensated for the value it provides, at the margin, by avoiding clearing (more costly) separate offers for each requirement.

In the co-optimized day-ahead market, cleared energy offers from physical supply resources (*e.g.,* generation and imports) participate in satisfying *two* day-ahead market requirements: (1) the market-clearing requirement of participants' bid-in energy demand; and (2) the system's forecast energy requirement. Therefore, those energy supply offers are paid both the day-ahead LMP (for 1) *and* the Forecast Energy Requirement Price (for 2). Stated differently, *without* that energy offer in the day-ahead market, the system would have incurred *both* costs to replace it: the day-ahead LMP *and* the Forecast Energy Requirement Price.

In contrast, an energy call option offer cleared for energy imbalance reserve participates in satisfying only the forecast energy requirement; it does not participate in satisfying the market-clearing requirement of participants' bid-in energy demand. Accordingly, it is paid only the Forecast Energy Requirement Price (which, as noted, is equal to the energy imbalance reserve price).

The substitution principle. In an efficient market, two goods that are perfect substitutes (for satisfying a demand or requirement) must be paid the same price for it. Being perfect substitutes, they are identically situated to the purpose for which the price applies, so discriminatory rates cannot be economically justified.

In the co-optimized day-ahead market, physical supply resources' cleared energy and cleared energy imbalance reserve are perfect substitutes *for satisfying the forecast energy requirement.* Clearing another MWh of one means the market clears a MWh less of the other, in a perfect 1-to-1 ratio. To satisfy the substitution principle, each MWh of their cleared energy and energy imbalance reserve must be paid the same Forecast Energy Requirement Price. The co-optimized day-ahead market achieves this because the Forecast Energy Requirement Price is equal to the energy imbalance reserve price.

Note that cleared energy supply and energy imbalance reserve are *not* substitutes for satisfying market participants' day-ahead market energy demand. That demand is for day-ahead forward sales of energy, and energy imbalance reserve is not a forward sale of energy. Thus, cleared energy supply is paid the day-ahead LMP for serving that demand (in addition to the forecast energy requirement price), but energy imbalance reserve is not paid the day-ahead LMP.

► **Implications.** Viewed from a broader market and reliability perspective, these properties of the co-optimized day-ahead market have three important implications.

First, incorporating the forecast energy requirement into the day-ahead market means that physical supply resources will (typically) receive greater total day-ahead market compensation, relative to the current energy-only day-ahead market design. This is because (1) the day-ahead market will tend to clear more *energy* with the addition of the forecast energy requirement, as explained in Section 6.2.2; and (2) the *total* day-ahead price paid to supply resources – that is, the sum of the day-ahead LMP and the Forecast Energy Requirement Price – is greater than the day-ahead LMP alone in an energy-only day-ahead market design (compare Figures 6-2 and 6-3).[98] In simple terms, the day-ahead market will now clear a quantity of energy farther 'up' the energy supply curve – and with energy imbalance reserve will now close the gap as required for a reliable next-day operating plan.

Second, all of the prices and compensation rates in this day-ahead co-optimized market design are economically appropriate, and are based on sound economic principles applicable to markets when there are multiple products. In simple terms, the day-ahead market will better signal, through transparent and competitive market prices, the costs of ensuring that the forecast energy requirement of a reliable next-day operating plan is satisfied. The forecast energy requirement is now a transparently priced, 'in-market' reliability requirement, and no longer an opaque, unpriced

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[98] This observation is consistent with the findings of the Impact Assessment. For the central cases evaluated, the day-ahead LMPs are slightly lower under the Energy Security Improvements cases than under the current market rules, but that change is much smaller than the larger offsetting size of the forecast energy requirement price. *See* Impact Assessment at p. 48 (Table 8).

'out-of-market' reliability requirement enforced after the day-ahead market is conducted.[99] In doing so, it advances the Commission-approved corporate mission of the ISO to "provide an opportunity for a participant to receive compensation *through the market* for a service it provides in a manner consistent with proper standards of reliability."[100]

Third, the resources that cover the gap between the forecast energy requirement and the energy cleared from physical supply resources will now have a Day-Ahead Energy Imbalance Reserve Obligation, consistent with the energy option settlement design. Their day-ahead compensation, and financial consequence for non-performance under the energy option settlements, addresses the misaligned incentives problem that exists for these resources today. Thus, for all of the reasons detailed in Sections 4 and 5, those resources will have stronger incentives under the Energy Security Improvements to arrange fuel to ensure they can reliably operate the next day.

6.2.4 Frequently Asked Questions

During the stakeholder review process over the past year, a number of questions commonly arose concerning the co-optimized day-ahead market's pricing and payments. For the Commission's benefit, we address many of these frequently asked questions and answers here.

1. **Q:** *Why is it appropriate for all generation that clears energy in the day-ahead market to be paid the Forecast Energy Requirement Price? Why do inframarginal supply resources (such as nuclear and run-of-river hydroelectric) need any new market incentives for fuel security?*

   A: The concept underlying uniform, market-clearing prices is that each seller is paid the same rate for contributing the same service. From an economic perspective, this is desirable because each seller's contribution avoids the same cost – the cost to procure from another (extra-marginal) seller with a higher offer price.

   In this way, each inframarginal resource that sells energy in the day-ahead energy market – assuming both nuclear and hydroelectric resources are such – provides the same valuable contribution to the forecast energy requirement. Their supply avoids the need to procure additional energy, at the margin, from a more costly resource to meet that requirement. If the energy procured from inframarginal resources defers the need to procure additional day-ahead energy from a more costly supplier that would have to make expensive fuel arrangements, then the inframarginal resources should be properly compensated for the value they provide in avoiding such higher-cost outcomes – *i.e.,* they should be paid the uniform, market-clearing Forecast Energy Requirement Price.

2. **Q:** *Can the Forecast Energy Requirement Price be put 'into' the LMP, like the congestion and the energy-loss components of the day-ahead LMP?*

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[99] *See* Brandien Testimony at pp. 19-21.

[100] Tariff Section I.1.3(b) (emphasis added).

A. Including the Forecast Energy Requirement Price into the day-ahead LMP would result in the wrong price signal to demand (that is, to buyers) participating in the day-ahead energy market. Each additional MWh of energy procured in the day-ahead market has a cost, based in part on the marginal energy supply offer that would be cleared to satisfy it; but the additional MWh of energy procured also *saves* the system one MWh of energy imbalance reserve, reducing the cost by the energy imbalance reserve price.

In short, if the Forecast Energy Requirement Price was incorporated 'into' the day-ahead LMP, then buyers in the wholesale market would face a price signal for day-ahead energy purchases that ignores this cost saving benefit, and that therefore exceeds the system's proper marginal cost to serve them. That inefficiently high price signal to demand would discourage demand participation in the day-ahead market and result in inefficiently low total energy clearing in the day-ahead market – *worsening* the day-ahead market's longstanding energy gap problem, not solving it.

3. **Q:** *Is that why the cost allocation for the Forecast Energy Requirement Price must be allocated to real-time demand (load), rather than day-ahead cleared demand?*

A: Yes, exactly. If the cost of the payments made to day-ahead energy suppliers at the Forecast Energy Requirement Price were allocated to day-ahead cleared demand, the effective price of energy to buyers in the day-ahead market would be the same as if the Forecast Energy Requirement Price was incorporated 'into' the day-ahead LMP. The perverse consequences of that incorrect price signal are the same as noted in the answer to Question 2.

4. **Q:** *Does the Forecast Energy Requirement Price constitute a "double-payment" for energy supply resources?*

A: No. The sum of the day-ahead LMP and the Forecast Energy Requirement Price is the marginal cost of energy supply in the day-ahead market. That marginal-cost based pricing logic is the same economic rationale for suppliers' energy payment rate in the day-ahead energy market today. With co-optimized day-ahead energy and energy imbalance reserve, that total payment rate is comprised of two transparent, uniform prices: one portion of the total payment rate is the marginal cost of serving participants' day-ahead energy demand, and the other portion is the *incremental* marginal cost of the forecast energy requirement. Those are different things, not a "double-payment" for the same thing.

5. **Q:** *Is the Forecast Energy Requirement Price another form of uplift?*

A. No. In the Tariff, "uplift" is called Net Commitment Period Compensation (NCPC). NCPC is a resource-specific, discriminatory payment intended to ensure minimum cost recovery when the ISO accepts a resource's offer at a market price below the resource's costs.

The Forecast Energy Requirement Price is distinct from, and not a form of, NCPC. First, the Forecast Energy Requirement Price represents the marginal cost of satisfying a market-wide purchase requirement. Second, it is a uniform, transparent price paid to all resources that contribute to satisfying this requirement. And third, it is not resource-specific, and it is not designed to provide energy offer cost recovery if the ISO accepts a resource's offer at a market price below the resource's costs.

6. Q: *With the Forecast Energy Requirement Price paid to day-ahead energy suppliers, but not charged to buyers, there will be a settlement imbalance between day-ahead market's energy credits and charges, right? Does such an imbalance exist in today's day-ahead market?*

A: Yes. Today, the energy-only day-ahead market's total credits to sellers and charges to buyers do not balance. One reason is congestion pricing. That (typically) results in the total payments by demand, at their LMPs, exceeding the total payments to suppliers, whenever the day-ahead market solution is constrained by transmission. That settlement imbalance is allocated through a separate mechanism outside the day-ahead market (namely, the existing Financial Transmission Rights mechanism). A second reason is marginal loss pricing, which again results in total payments by demand being different from total payments to suppliers. Those settlement imbalances have their own allocation mechanism (namely, the Marginal Loss Revenue Fund mechanism).

The payments to supply resources at the Forecast Energy Requirement Price also create a settlement imbalance in the day-ahead market. But clearly such day-ahead market settlement imbalances are neither new or novel; they simply require a cost-allocation method outside the day-ahead market that appropriately reflects cost-allocation principles. In this case, the cost of satisfying the forecast energy requirement is allocated (primarily) to the system's real-time load, on beneficiary-pays principles. We address that in greater detail in Section 6.6 below.

7. Q: *Do buyers now have any form of "price protection" against the real-time price, if they do not purchase energy day-ahead?*

A: In a sense, yes. There are two useful perspectives on this question. First, the buyers who are allocated the costs of day-ahead energy imbalance reserve are paying for the right, but not the obligation, to "show up" in real-time and know that there are physical supply resources scheduled to cover their real-time demand (up to a limit, that is – the amount of energy call options cleared in the day-ahead market). And yes, they are 'hedged' at the energy call option strike price for their real-time price exposure (again, up to that limit). They pay for that hedge, up front, in the form of the energy imbalance reserve price, which is the price that the energy call option sellers are willing to accept for it.

The second perspective is that wholesale buyers have always been afforded that right, but have simply not been charged for it. This is because, today, the ISO nonetheless ensures, after the day-ahead market is conducted, that there are sufficient resources to satisfy the forecast energy requirement. So the main difference is simply that the real cost of this (previously unpriced) option to "show up" in real-time will be made clear to the market. Specifically, the day-ahead market will transparently price and compensate suppliers for providing this option, and will allocate its costs to wholesale market participants that avail themselves of it (*see* Section 6.6.4).

8. **Q:** *In Figure 6-1, the day-ahead LMP is less than the real-time LMP will be, assuming the load forecast is accurate. Why doesn't virtual demand, and demand bidding generally, close the 'energy gap' between the total energy cleared in the day-ahead market and the forecast energy requirement?*

   A. There are a number possible reasons why. These include the allocation of NCPC (uplift) costs to virtual transactions that deter their market participation; potentially, the systematic under-scheduling of expected real-time demand by large wholesale market buyers (which may reduce the day-ahead market clearing price); and the fact that price convergence of the day-ahead and real-time LMPs does not necessarily close the gap between cleared energy from physical supply resources and forecast energy demand. One reason for the latter is that if the market clears virtual supply offers, then there may still remain less energy cleared from physical supply resources than the total energy cleared in the day ahead market – and an energy gap to be filled in preparing a reliable next-day operating plan (*see, e.g.,* case (d) in Section 6.1.1).

   It is difficult to know for certain how much each of these possible factors contributes to the energy gap, and why demand behavior (whether virtual or otherwise) does not consistently close it. Empirically, there is an energy gap between the total energy cleared from physical supply resources in the day-ahead market and the forecast energy requirement (*see* Section 6.1.2).

9. **Q:** *Is energy imbalance reserve intended to serve as a surrogate for (insufficient) virtual transaction participation in the markets?*

   A: No. Energy imbalance reserve, and incorporating the forecast energy requirement in the day-ahead market, are complements to, not substitutes for, virtual transactions in the day-ahead market. In fact, as we will see in later examples, virtual transactions can play a valuable role in facilitating efficient day-ahead market pricing in this co-optimized day-ahead market design (*see* Section 7.7.2).

   Energy imbalance reserve has a much simpler intended purpose: to ensure that the next day operating plan has sufficient physical resources that the ISO can call on to cover the forecast energy requirement; and to ensure that, consistent with sound market design, the costs of that reliability requirement are transparently and competitively priced in the markets. By doing so, the design provides stronger incentives for resources to arrange energy supplies in advance of the operating day, helping to better address the region's energy security concerns.

6.2.5 Further Observations: Demand Behavior and Opportunity Costs

In this section, we note several additional observations and properties of the co-optimized day-ahead market with energy and energy imbalance reserve. These concern equilibrium behavior and day-ahead demand dynamics, and the impact of opportunity costs on prices. We offer these observations to provide a more complete understanding of these aspects of the new market design.

► **Equilibrium behavior.** The analysis surrounding Figures 6-2 and 6-3 above illustrates the mechanics and interpretation of market clearing and pricing. It takes the existing supply and demand curves for energy as given (that is, the same) before and after the introduction of co-optimized market clearing. However, in markets, participants react to changing conditions.

In comparing Figures 6-2 and 6-3, note that the day-ahead LMP paid by buyers, *in these examples,* decreases because clearing day-ahead energy farther 'down' the market's energy demand curve provides a cost savings by reducing how much energy imbalance reserve must be procured. That is the economically correct outcome if the market participants' bids to buy energy day-ahead do not change.

However, in practice, we should expect buyers to react to the lower day-ahead LMP by increasing the quantities they are willing to purchase in the day-ahead market. That response by market-level day-ahead energy demand will tend to raise the day-ahead LMP (bringing it closer to its value in real-time).[101]

We highlight this demand-side market response for two reasons. First, while the prior analysis (again, taking supply and demand curves as given) suggests that the day-ahead LMP will be lower under the new design, buyers' economic incentives suggest otherwise. Accounting for the economic incentives of markets to react to these price signals, it is reasonable to expect the average difference between day-ahead and real-time LMPs may not differ appreciably from the current market design.

Second, this response by day-ahead demand will tend to diminish the amount of energy imbalance reserve that is procured in the co-optimized day-ahead market. In fact, it is possible that on many days the energy imbalance reserve cleared may be zero. [102] That, however, should not be interpreted to indicate energy imbalance reserve is unnecessary – rather, that outcome is may commonly occur *because* we have incorporated and now priced the forecast energy requirement within the day-ahead market design.

► **Opportunity costs and pricing outcomes**. In the examples in this section (including those in Section 6.3 below), there is a single day-ahead ancillary service product: energy imbalance reserve. Because there is only one ancillary service product, suppliers have no opportunity costs in providing it, relative to other ancillary services. In actuality, however, the Energy Security Improvements include other day-ahead ancillary service products as well. Because of this, providing one ancillary service will, for the marginal seller, tend to come at an opportunity cost of not selling another service (if another ancillary service has a higher clearing price).

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[101] On an average annual basis, the difference between day-ahead and real-time LMPs in New England is small. In 2018, the average Hub price was $44.13/MWh in the day-ahead market and $43.54/MWh in the real-time market. *See* 2018 Annual Markets Report, dated May 23, 2019, available at https://www.iso-ne.com/static-assets/documents/2019/05/2018-annual-markets-report.pdf, at p. 54.

[102] This observation is consistent with the Impact Assessment's results. For the central cases studied, it finds that because of the substitution of energy for reserves, in the majority of all hours the cleared energy imbalance reserve is zero. *See* Impact Assessment at p. 50 (Table 10 and discussion thereof).

These product pricing interactions are important, in practice. In particular, inter-product opportunity costs can, and in many cases will, result in a higher day-ahead LMP, a higher forecast energy requirement price, or both, if there is an opportunity cost of not selling energy when cleared to provide another ancillary service (that is, other than energy imbalance reserve). For that reason, we will provide examples to illustrate these product pricing interactions after we introduce the additional ancillary services (generation contingency reserve and replacement energy reserve) in Section 7.

6.3 Example 3: Clearing and Pricing Mechanics with the FER

To illustrate the pricing and clearing concepts of the prior section, we next provide a pair of simple numerical examples. The main points of these examples are to show how the day-ahead market will tend to clear closer to the forecast energy requirement with energy imbalance reserve, and to show how the forecast energy requirement price is determined.

6.3.1 Example 3-A: Market Clearing without the Forecast Energy Requirement

We first consider an example of day-ahead market clearing with energy only, without the forecast energy requirement. From this, we will then examine how the market outcomes change with energy and energy imbalance reserve co-optimization.

► **Assumptions.** In this example, there are eight generators, Generator A through H. Their energy supply offer prices and quantities (*i.e.,* resource capacities) are shown in the first two numerical columns of Table 6-1. Note the generators are listed in ascending order of their energy offer price.

Below the energy supply offers in Table 6-1 are listed the bid prices and quantities of three energy demand bids. In this example and (most) others that follow, we will assume that market participants submit priced energy demand bids into the day-ahead market (rather than "fixed," or unpriced, day-ahead demand bids for energy).[103]

[103] For context, New England's day-ahead market does not clear with "fixed," or unpriced, demand bids near the margin. Approximately 1/3 of all day-ahead demand bids (by volume) are priced, and in practice the day-ahead market clears in the price-sensitive range of the aggregate demand curve. *See* 2018 Annual Markets Report, dated May 23, 2019, available at https://www.iso-ne.com/static-assets/documents/2019/05/2018-annual-markets-report.pdf, at pp. 73-75 (Figures 3-19 and 3-20). To capture this important feature of market participants' behavior, our numerical examples here assume that demand participates with priced demand bids.

Table 6-1. Assumptions and Market Outcomes for Example 3-A					
		Supply Offer Assumptions			Day-Ahead Outcomes
		Energy Supply Offers			Market Awards
		Price	Quantity		Energy
	Generator	($/MWh)	(MWh)		(MWh)
[1]	A	$0	300		300
[2]	B	$10	150		150
[3]	C	$36	150		150
[4]	D	$42	200		-
[5]	E	$60	200		-
[6]	F	$72	50		-
[7]	G	$78	50		-
[8]	H	$210	150		-
[9]	**Totals**		**1250**		**600**
		Demand Assumptions			
		Energy Demand			
		Price	Quantity		
		($/MWh)	(MWh)		
[10]	Bid 1	$55	500		500
[11]	Bid 2	$40	200		100
[12]	Bid 3	$35	100		-
[13]	**Totals**		**800**		**600**

► **Market outcomes.** With only one product – energy – the market will clear where energy supply and demand intersect. This is readily apparent in Figure 6-4, which shows the supply and demand diagram for the bids and offers listed in Table 6-1. The three demand bids form a descending stair-step demand "curve", and are drawn in purple. We show the supply offer bids from (only) generators B, C, and D, in Figure 6-4, to focus on the relevant range of the supply curve where the market clears.

Supply and demand intersect at a quantity of 600 MWh. In this example, any other outcome would not align marginal benefit and marginal cost. The market participant with marginal demand bid 2 is willing to pay at most $40/MWh, but the next MWh is offered by Generator D at a price of $42/MWh. Thus, clearing one more MWh would result in a marginal cost exceeding its marginal benefit; and clearing one MWh less than 600 would fail to procure one (last) MWh where marginal benefit (of $40/MWh) exceeds its marginal cost (that of Generator C, at $36/MWh).

The market-clearing price in this example is $40/MWh, where supply and demand intersect. Thus, the day-ahead LMP is set by demand bid #2, at its $40/MWh bid price. At this price, all buyers with cleared demand bids are willing to pay $40/MWh or more, and no uncleared demand bids are willing to pay more. Similarly, all generators with cleared supply offers are willing to accept \$40/MWh or less, and no uncleared supply offers are willing to accept less.[104]

For what comes next, observe that in Figure 6-4, we have assumed a forecast energy requirement of 720 MWh. (This is shown below the horizontal axis, and labeled '$D_{\text{forecast energy}}$ = 720 MWh'). The 600 MWh of energy cleared in the market is well below this forecast energy requirement. Assuming (as we will for the moment) that the forecast materializes in real-time at 720 MWh, the real-time LMP will be higher than day-ahead, at \$42/MWh from Generator D.

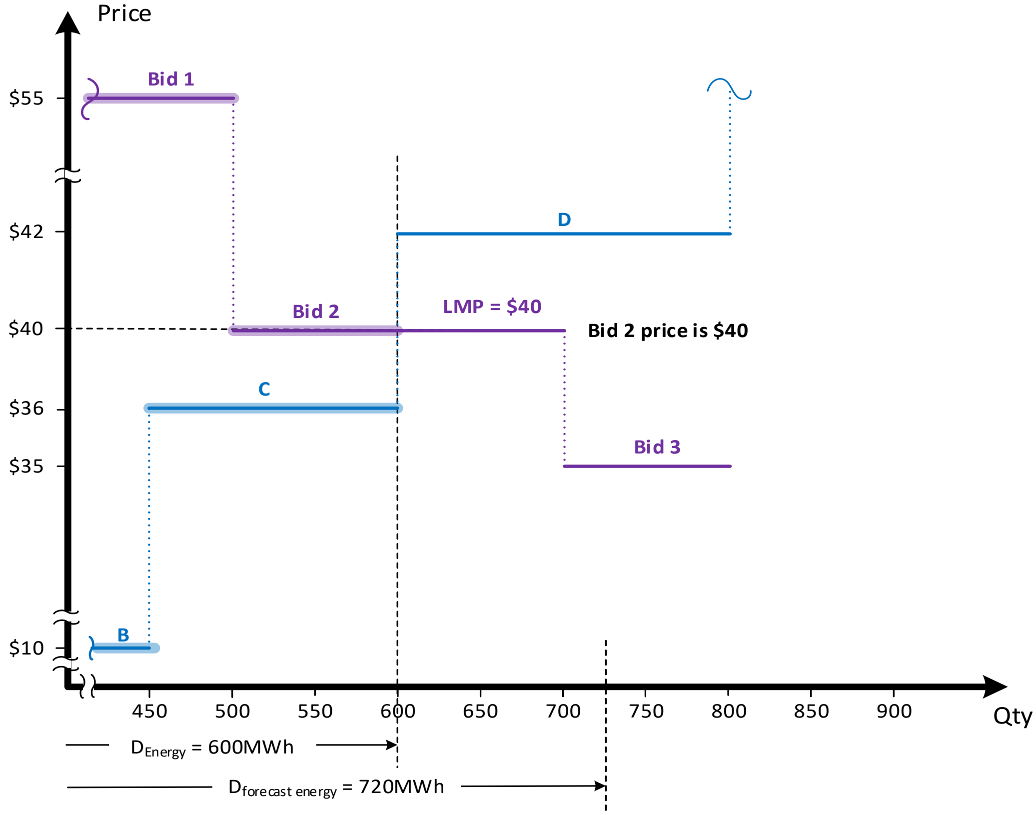

Figure 6-4. Market Outcomes for Example 3-A: No Forecast Energy Requirement

[104] In the day-ahead market, demand bids can, and do, set the market-clearing energy price. (This is common, but not always the case.) This is a consequence of economic clearing that seeks to align marginal benefit and marginal cost.

As in prior discussions, the day-ahead market has an energy gap of 120 MWh (the 720 MWh forecast less the 600 MWh that clears day-ahead). As illustrated in this example, under the current market construct Generator D has no day-ahead obligation, and market settlement in real-time if it is unable to operate the next day when called.

6.3.2 Example 3-B: Market Clearing with the Forecast Energy Requirement

We now extend this example by introducing the forecast energy requirement into the co-optimized day-ahead market with both energy and energy imbalance reserve.

The energy supply offers and demand bids are assumed to be unchanged from previous Example 3-A, and for convenience are reproduced in the first and second numerical columns of Table 6-2. Table 6-2 also lists the generators' assumed energy call option offer prices and quantities, which are submitted by Generators C through G.

Table 6-2. Assumptions and Market Outcomes for Example 3-B

		Supply Offer Assumptions				Day-Ahead Outcomes	
		Energy Supply Offers		Energy Option Offers		Market Awards	
		Price	Quantity	Price	Quantity	Energy	EIR
	Generator	($/MWh)	(MWh)	($/MWh)	(MWh)	(MWh)	(MWh)
[1]	A	$0	300			300	-
[2]	B	$10	150			150	-
[3]	C	$36	150	$2.59	100	150	-
[4]	D	$42	200	$2.59	100	100	20
[5]	E	$60	200	$5.05	90	-	-
[6]	F	$72	50	$5.54	50	-	-
[7]	G	$78	50	$5.82	50	-	-
[8]	H	$210	150			-	-
[9]	**Totals**		**1250**		**390**	**700**	**20**
		Demand Assumptions					
		Energy Demand		Forecast Energy			
		Price	Quantity	Quantity			
		($/MWh)	(MWh)	(MWh)			
[10]	Bid 1	$55	500			500	-
[11]	Bid 2	$40	200			200	-
[12]	Bid 3	$35	100			-	-
[13]	**Totals**		**800**	**720**		**700**	
				Day-Ahead Outcomes			
				Clearing Prices ($/MWh)			
				FERP		LMP	EIR
[14]				**$2.59**		**$39.41**	**$2.59**

The market-clearing outcomes are summarized in the last two columns of Table 6-2. Generators A through D clear energy supply offers against demand bids 1 and 2. Total day-ahead cleared energy is now 700 MWh, as shown in the second-to-last column, rows [9] and [13]. The sum of total cleared energy and energy imbalance reserve in the last two columns of row [9] is 700 MWh + 20 MWh = 720 MWh, which equals the forecast energy requirement.

► **The market-clearing outcomes align marginal benefit and marginal cost.** Let's now consider why the day-ahead market, with the same energy supply offers and demand bids as in Example 3-A, now clears 700 MWh of energy.

Figure 6-5 shows the supply and demand diagram for the assumptions and results in Table 6-2. As before, participants' demand bids for energy form a descending stair-step demand 'curve' and are indicated in purple. The supply offers of Generators B, C, and D, which span the range where the market clears, are shown in the ascending stair-step supply 'curve' in blue. The energy call option offer prices for Generator D's remaining capacity (that is, its capability not cleared as energy), and for Generator E, are shown in the orange stair-step EIR supply curve. Note that, like Figure 6-3 earlier, the EIR supply curve is drawn starting from the quantity of energy cleared in the market, here 700 MWh.

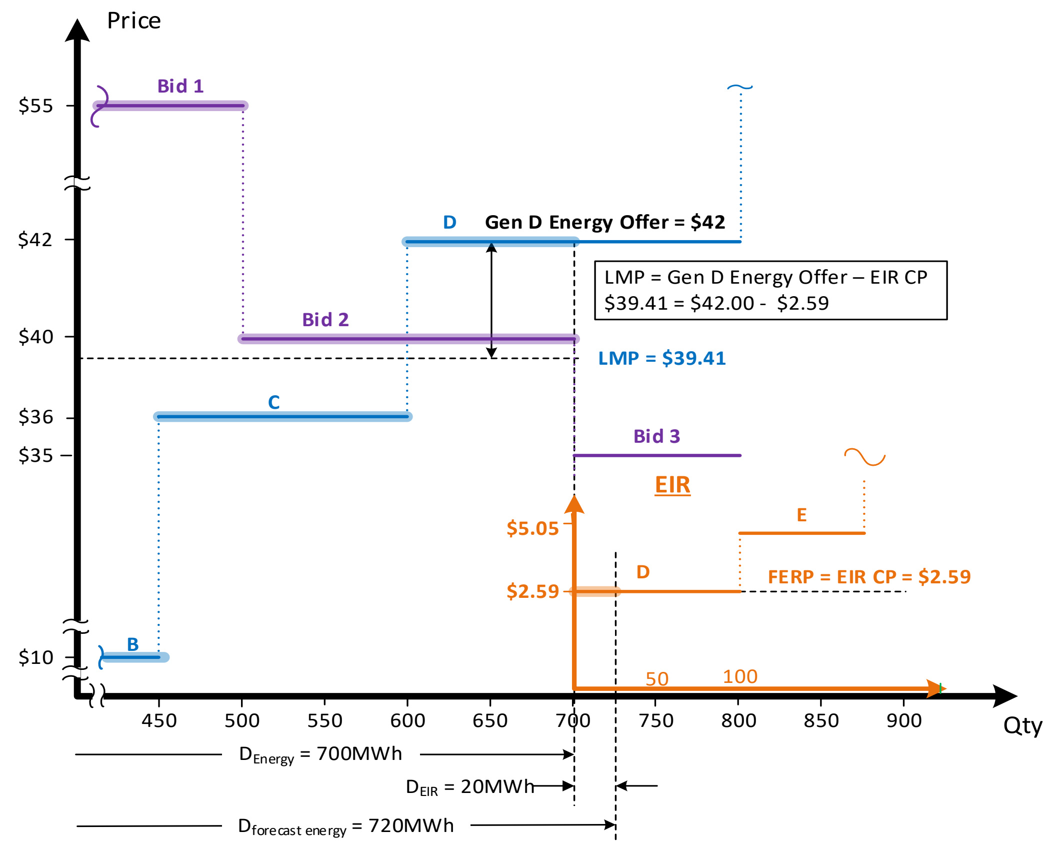

Figure 6-5. Market Outcomes for Example 3-B with the Forecast Energy Requirement

To see why the market clears 700 MWh of energy, consider the marginal benefit and marginal cost of serving demand of the last, 700th MWh. The marginal benefit is the value of demand bid 2 at that last MWh, or $40/MWh.

Now consider the marginal cost incurred by the system to serve that last MWh of energy demand. That has two pieces: the marginal cost of energy supply, *less* the marginal cost savings from one less MWh of energy imbalance reserve. The 700th MWh of energy supply comes from Generator D, at an offer price of $42/MWh. However, by clearing the last MWh of energy, the system is able to clear one less MWh of energy imbalance reserve. The marginal cost of energy imbalance reserve is $2.59/MWh, also from Generator D, and so the marginal cost savings from less energy imbalance reserve is $2.59/MWh. Putting the pieces together, for the 700th MWh of energy,

MC of serving energy demand = $42/MWh energy – $2.59/MWh EIR = $39.41/MWh.

The 700th MWh of energy therefore has greater marginal benefit, $40/MWh, than its marginal cost. Thus, the market clears (at least) 700 MWh.

Of course, it is also important to check that clearing *another,* 701st MWh of energy, would have marginal cost in excess of its marginal benefit. Here, the marginal benefit of the 701st MWh would be that of demand bid #3, which is willing to pay only up to $35/MWh. The marginal cost of serving that 701st MWh of energy is the same as before, at $39.41/MWh. Therefore, the market would *not* clear the 701st MWh, as its marginal cost ($39.41/MWh) exceeds its marginal benefit ($35/MWh).

There are two notable points of these calculations so far. First, the co-optimized market clearing process is still governed by the same properties of an efficient market – the quantities cleared align marginal benefit and marginal cost. However, the marginal cost of serving energy demand is different when the market also clears energy imbalance reserve, because additional energy supply substitutes (*i.e.,* avoids the cost of) energy imbalance reserve at the margin. We highlight this logic because this economic balancing of marginal benefit and marginal cost in a co-optimized day-ahead market illustrates what is meant by when the ISO (and the Tariff) indicates that it performs an "economic commitment and dispatch" to clear the day-ahead market.[105]

Second, as noted previously in Section 6.2.2 and 6.2.5, the net impact of this property is that the market will tend to clear energy 'farther up' the energy supply curve, with higher total quantities than in the energy-only day-ahead market of today under the same conditions.

► **The market-clearing prices.** The market clearing prices are determined by the same logic. First consider the Forecast Energy Requirement Price. This is the marginal cost of an incremental change in the forecast energy requirement. If that requirement increased by one MWh, from 720 MWh to 721 MWh, the least-cost means to satisfy it would be to clear an additional (*i.e.,* 21st) MWh of energy imbalance reserve from Generator D, at a marginal offer price of $2.59. See Figure 6-5.

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105 *See, e.g.,* Tariff Sections III.1.7.6(a), III.1.10.8(a)(ii), and III.2.2.

Therefore, the Forecast Energy Requirement Price and energy imbalance reserve price are $2.59/MWh.

The day-ahead LMP calculations are summarized in Table 6-3. At the market-clearing quantity of 700 MWh, the marginal bid or offer is the offer of Generator D, at $42. However, procuring another MWh of energy from it would reduce – or "re-dispatch down" – its EIR award by 1 MWh, at a cost savings of $2.59/MWh. The marginal cost of serving energy demand is the difference, $42/MWh - $2.59/MWh = $39.41/MWh, so the day-ahead LMP is therefore $39.41. The day-ahead LMP is not set *at* any one bid's or offer's price, but by the *difference* in two marginal offer prices: One for energy, and the other for energy imbalance reserve.

Table 6-3. LMP Calculation for Example 3-B			
	Change in Total (Production) Costs for One More MWh of Energy Demand		
[1]	+ 1 MWh of energy from Generator D	$42.00	***Energy offer price of marginal Gen D***
[2]			***(results in one less MWh of EIR from Gen D)***
[3]	"Re-dispatch" EIR		
[4]	- 1 MWh of EIR from Generator D	($2.59)	***"Savings" from one less MWh of EIR from Gen D***
[5]		**$39.41**	***Marginal cost of serving energy demand (LMP)***

► **Who gets paid what.** On the demand side, the market participants with demand bids 1 and 2 are charged the day-ahead LMP of $39.41/MWh for the MWh they clear. Note that all cleared demand bids are willing to pay the day-ahead LMP or more, and that no uncleared demand bid is willing to pay more. The settlement rate of the day-ahead LMP is therefore consistent with an efficient market-clearing outcome for the demand side of the market.

On the supply side, Generators A, B, C, and D are credited the sum of the day-ahead LMP and the Forecast Energy Requirement Price for the MWh of energy they clear, or $39.41/MWh + $2.59/MWh = $42/MWh. This settlement rate is the marginal cost of energy supply, as determined by marginal Generator D's energy offer price of $42/MWh. In this way, all cleared energy supply offers are willing to accept the settlement rate of $42/MWh or less, and no uncleared energy supply offers are willing to accept less. The settlement rate of the day-ahead LMP *plus* the forecast energy requirement price is therefore consistent with market-clearing outcome for the energy supply side of the market.

In addition, Generator D is credited the energy imbalance reserve price of $2.59/MWh for each MWh of energy imbalance reserve it clears. It is willing to accept this settlement rate of $2.59/MWh, and no uncleared energy option offer is willing to accept less. The settlement rate of the energy imbalance reserve price is therefore consistent with market-clearing outcome for the energy option supply side of the market. Note further that the clearing prices settlement rates ensure that marginal Generator D is indifferent between providing energy and energy imbalance reserve.

Last, there is the cost of the Forecast Energy Requirement Price and energy imbalance reserve price to be allocated. This total cost is $2.59/MWh multiplied by the 720 MWh forecast energy requirement (with 700 MWh of that being forecast energy requirement payments to Generators A, B, C, and D for energy, and 20 MWh of that being energy imbalance reserve payments to Generator D). In this example, that cost would be allocated to real-time load (*see* Section 6.6.2). In simple terms, buyers ultimately pay the cost of operating a reliable power system, and those costs are now reflected through transparent market prices.

► **The main points.** There are two main points of Example 3-B. First, with the forecast energy requirement incorporated into the day-ahead market, an additional 120 MWh clears for energy or for energy imbalance reserve. Both obligations provide a day-ahead schedule that Generator D can expect to operate to in real-time, given the forecast energy demand. Generator D now receives day-ahead compensation for those 120 MWh to arrange energy supply in advance of the operating day.

Second, note that if Generator D did not arrange energy to operate, then it would need to 'buy out' both its 100 MWh day-ahead energy award at the real-time LMP, and its 20 MWh energy imbalance reserve award at the real-time LMP less the strike price (if positive). That would be a costly outcome. For its 100 MWh energy obligation, Generator D's replacement cost for real-time energy would be (at least) $60/MWh from Generator E (assuming Generator E was available in real-time; it could be higher still if not). Compare that to the situation in today's day-ahead energy market in Example 3-A, where Generator D did not clear in the day-ahead market – and, if it does not arrange fuel and cannot operate in real-time, it would have incurred no charges at all.

For this reason – much as illustrated for the energy option award in earlier Examples 1 and 2 in Section 5 – the co-optimized day-ahead energy and energy call option design provides much stronger incentives for the resources the ISO relies upon to arrange energy supplies in advance of the operating day.

► **Co-optimization and cost-effectiveness**. As noted at the outset of this section, in a co-optimized day-ahead market, the cleared quantities of energy and energy imbalance reserves are simultaneously determined (*i.e.,* endogenous) within the market clearing process. That is essential to produce cost-effective outcomes that reflect marginal benefits and marginal costs.

For instance, if the energy option offer prices comprising the energy imbalance reserve supply curve were significantly higher than shown in Table 6-2, the market would clear less energy imbalance reserve and more energy instead. That substitution of energy for energy imbalance reserve, within the co-optimization process, efficiently reduces the cost impact of a potential day with higher-than-normal energy option offer prices, while still satisfying the forecast energy requirement.

Similarly, if energy supply offers are higher than normal, the day-ahead market's clearing would substitute more energy imbalance reserve for energy.[106] In this way, the co-optimized day-ahead market design is structured to produce the most cost-effective scheduling of the system's resources,

[106] In this example, that would occur if Generator D's energy supply offer price exceeded $42.59/MWh, in which case the market would not clear Generator D's now expensive energy and instead purchase from it 120 MWh of less expensive energy imbalance reserve.

given their offer prices, while simultaneously satisfying both the forecast energy requirement and market participants' day-ahead bid-in energy demand.

6.4 The Forecast Energy Requirement: Details

In this section, we provide additional detail on the formulation of the forecast energy requirement that will be incorporated into the co-optimized day-ahead market clearing process with these Energy Security Improvements. This also has implications for the settlement of virtual transactions in the day-ahead market, which we explain presently. We also summarize various new tariff provisions related to the forecast energy requirement.

6.4.1 Forecast Energy Requirement Specification

The forecast energy requirement is part of the ISO's preparation of a reliable next-day operating plan and, at present, is implemented through operating procedures performed after ("outside" of) the day-ahead market.[107]

In the existing energy-only day-ahead energy market, there is a single market clearing requirement: total energy supply equals total energy demand. In incorporating the forecast energy requirement into the day-ahead market, there will be an additional, second clearing requirement for energy and energy imbalance reserve from physical supply resources. Because they are evaluated simultaneously, we summarize next the existing market-clearing requirement and the market's new forecast energy requirement.

► **The market-clearing requirement specification.** Stated in summary form, the existing day-ahead market-clearing requirement (MCR, for short) can be expressed as:[108]

(MCR) $$GEN_h + IMP_h + INC_h = DMD_h + EXP_h + DEC_h$$

The left-hand side of the equation is total cleared supply, and the right-hand side is total cleared demand. Stated more precisely, on the left-hand side GEN_h is the total MWh of all energy supply offers cleared in the day-ahead market for hour *h* from generation resources (including active demand response that is treated as "supply" in the day-ahead market). IMP_h is the total MWh of all external transaction energy imports into New England cleared (scheduled) for hour *h* in the day-ahead market. The term INC_h is the total MWh of Increment Offers (virtual supply) cleared in the day-ahead market for hour *h.*

[107] *See* System Operating Procedure RTMKTS.0050.0010 – Perform Reserve Adequacy Assessment, available at https://www.iso-ne.com/static-assets/documents/rules_proceds/operating/sysop/rt_mkts/sop_rtmkts_0050_0010.pdf. *See also* Brandien Testimony at pp. 19-21.

[108] For simplicity, this ignores energy losses. Separate constraints (omitted here) characterize transmission limits in the market-clearing process.

On the right-hand side of the equation, DMD_h is the total MWh of all participant-submitted energy demand bids cleared in the day-ahead market for hour *h,* exclusive of exports and virtual demand bids. EXP_h is the total MWh of all external transaction energy exports from New England cleared (scheduled) for hour *h.* DEC_h is the total MWh of Decrement Bids (virtual demand) cleared in the day-ahead market for hour *h.*

The day-ahead market-clearing requirement formulation in expression (MCR) does not change with co-optimization. It will continue to ensure that the day-ahead market clears equal amounts of energy supply and demand. As explained in Sections 6.2 and 6.3, however, the total MWh of energy supply and demand that clear will change with the addition of the forecast energy requirement to the day-ahead market.

► **The forecast energy requirement specification***.* The forecast energy requirement determines the energy and energy imbalance reserve needed to cover the forecast energy demand for (each hour of) the next operating day. It is implemented as a new, additional constraint within the co-optimized day-ahead market-clearing solution.

Stated more precisely, the forecast energy requirement (FER, for short) for energy and energy imbalance reserve can be expressed as:

(FER) $$GEN_h + IMP_h + EIR_h \geq LF_h + EXP_h$$

On the left-hand side of this equation, GEN_h and IMP_h are the same total day-ahead MWh cleared for hour *h* from generation and imports that appear in equation (MCR). The new term EIR_h is the total MWh of energy imbalance reserve that the day-ahead market will now clear for hour *h* to satisfy this forecast energy requirement.

On the right-hand side of this equation, LF_h is the ISO's system-wide load forecast for hour *h* of the operating day (more about which below). EXP_h is the same total MWh of day-ahead cleared exports as in equation (MCR).

A note on terminology. Technically, the forecast energy requirement is a *constraint*, as expressed in equation (FER). When it will cause no confusion, it can be useful to also refer to the forecast energy requirement as the *value* of the load forecast, which is the term LF_h that appears on the right-hand side of equation (FER). For precision, in the Tariff we introduce the defined term Forecast Energy Requirement Demand Quantity to refer to the value of the load forecast, LF_h, that appears in equation (FER) (*see* new Tariff Section III.1.8.6).

► **Simultaneous determinations of energy and energy imbalance reserve***.* It is important to note that when the forecast energy requirement constraint is incorporated with the day-ahead market clearing process, four of the five terms in expression (FER) will be endogenously determined by the market. The only "fixed" value in that expression is the load forecast, which is determined in the ISO's load forecasting process (just) prior to the day-ahead market. All of the other components are simultaneously determined in the course of clearing equal amounts of total energy supply and demand, based on all energy supply offers, demand bids, and energy call option offers.

As a simple example, consider the numbers from Examples 3-A and 3-B in Section 6.3 above. Neither imports and exports, nor virtual transactions, were present in that example, so the terms IMP_h, EXP_h, INC_h, and DEC_h are all zero. In Example 3-A, the energy-only case, the total cleared generation (from Generators A, B, and C) is 600 MWh and total cleared demand is 600 MWh (from demand bids 1 and 2). This satisfied the market clearing requirement in equation (MCR), but left an energy gap because the forecast energy requirement was 720 MWh.

When we added the forecast energy requirement in Example 3-B, the total cleared generation is 700 MWh (from Generators A, B, C, and D), and total cleared demand is 700 MWh (from demand bid 1 and more of demand bid 2). This again satisfies the market-clearing requirement in equation (MCR). The total cleared energy imbalance reserve is 20 MWh, which when added to the total cleared generation, matches the load forecast of 720 MWh. Both equation (MCR) and equation (FER) are now satisfied by the market-clearing solution.[109]

► **Load forecast, imports, and exports**. The energy supply counted toward the forecast energy requirement is the amount that cleared day-ahead from physical supply resources. Specifically, as equation (FER) shows, the day-ahead cleared energy from physical supply resources is all of the energy cleared from generation and imports (along with active demand response treated as "supply" in the energy market, which we include by reference here as cleared generation).

On the right hand side of equation (FER), the sum of the ISO's load forecast and day-ahead cleared exports represents the total expected energy demand for hour *h* of the next operating day. Importantly, in practice, the ISO's operational next-day load forecast is an estimate of real-time load *within* the New England Balancing Area; that is, it excludes imports or exports. Thus, the exports that economically clear in the day-ahead market are explicitly added to the right-hand side of the forecast energy requirement constraint (FER) to better estimate the system's total energy demand during the next operating day. This treatment of day-ahead cleared imports and exports mirrors how the forecast energy requirement is implemented today, as an "out of market" process after the day-ahead market is conducted.

The ISO's load forecast is an estimate of each upcoming hour's real-time electrical load system-wide. It is net (the effects) of distributed generation and other generation that does not participate in the wholesale electric market, such as behind-the meter photovoltaic output. The forecast is updated (at least) twice daily, and posted publicly at 6:00 a.m. and 10:00 a.m. each day. Each forecast update produces hourly load estimates for today, for tomorrow, and for the next day.[110]

On average, the forecast for the next operating day produced (just) prior to the day-ahead market (*i.e.,* the 10:00 a.m. update) is neither too high, nor too low. In 2018, the average hourly day-ahead load forecast error was –24 MW, and in 2019 it was +12 MW. These are very small, representing

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[109] The day-ahead co-optimized market will satisfy the requirements in equations (MCR) and (FER) in addition to the requirements for the other new day-ahead ancillary services (generation contingency reserve and replacement energy reserve, discussed in subsequent sections).

[110] *See* Three-Day System Demand Forecast, available at https://www.iso-ne.com/markets-operations/system-forecast-status/three-day-system-demand-forecast/.

approximately one-tenth of one percent of actual (realized) load. This indicates that on average, incorporating the load forecast into the market through the forecast energy requirement will not systematically to procure too much, nor too little, energy for the New England Balancing Area for the next operating day.

Of course, on any given day actual load in real-time may be higher or lower than forecast, in part due to the inherent variability of New England's weather.[111] This uncertainty presented additional operational risks, which are also appropriately addressed with these Energy Security Improvements. We discuss how these uncertainties can be properly addressed through the market using replacement energy reserve in Section 7.

6.4.2 Tariff Provisions

In this section we describe various rules governing energy and energy imbalance reserve co-optimization, the forecast energy requirement, and the associated new Tariff provisions in this filing.

► **Key terminology.** For clarity, several new Tariff provisions use the more economically-precise term "Demand Quantity" to reference numerical values that, in more common parlance, are referred to as "requirements." Specifically:

- New Section III.1.8.6 defines the Forecast Energy Requirement Demand Quantity, which is the ISO's day-ahead load forecast for the applicable market hour. Section III.1.8.6 references existing provision Section III.1.10.1.A(h), which governs the ISO's production and provision of the system's load forecast, consistent with the foregoing discussion in Section 6.4.1. In other words, this filing does not modify the ISO's existing load forecasting process.

- New Section III.1.8.5(f) defines the new Day-Ahead Energy Imbalance Reserve Quantity. Consistent with the foregoing explanations in Sections 6.2 through 6.4 of this paper, this quantity is endogenously determined within the market; it is not a fixed value. The Tariff language is therefore formulaic, capturing equation (FER) in Section 6.4.1, above. That is, the amount of energy imbalance reserve determined within in the co-optimized market's clearing is the amount necessary to close the 'gap', if positive, between the Forecast Energy Requirement Demand Quantity (*i.e.,* the load forecast for the applicable hour) and the total cleared energy from Generator Assets, Demand Response Resources (which participate as "supply" in the energy market), and net scheduled interchange (imports minus exports).

[111] The mean absolute error of the day-ahead load forecast was just under two percent in 2018 and 2019 (as a percent of actual load); in absolute terms, this corresponds to a mean absolute error of 275 MW and 246 MW in each year, respectively.

It is through this specification of the Day-Ahead Energy Imbalance Reserve Quantity that the forecast energy requirement, as expressed in equation (FER) in Section 6.4.1 above, is incorporated into the Tariff for purposes of clearing the co-optimized day-ahead market.

► **Co-optimization-related new tariff provisions.** Consistent with the design and economic rationale for energy and energy imbalance reserve explained throughout Section 6 of this paper, various new and revised portions of Sections III.1 and III.2 of the Tariff address co-optimized clearing of the day-ahead market.

The primary day-ahead market co-optimization provisions are contained in new Section III.1.10.8(a)(ii), revising existing Section III.1.10.8(a). These revisions extend the existing energy-only day-ahead market reflected in Section III.1.10.8(a) to a day-ahead market that clears both energy and ancillary services, and incorporates the forecast energy requirement. Of note:

- *Joint optimization.* The first paragraph in new Section III.1.10.8(ii) states that the day-market will be jointly optimized (that is, co-optimized) for energy and the new Day-Ahead Ancillary Services (including, by that defined term, Day-Ahead Energy Imbalance Reserve and the other new ancillary services discussed subsequently in Section 7 of this paper).

  The joint optimization expressly performs an economic commitment and dispatch. As explained in Sections 6.2 and 6.3 of this paper, that corresponds to the economic concept of seeking to align marginal benefits and marginal costs and is consistent with economically-efficient market outcomes, per the ISO's broader mission to create and sustain markets that are economically efficient (*see* existing Tariff Section I.3.1(b)).

- *Forecast energy requirement*. The first paragraph in new Section III.1.10.8(ii) also indicates that the market clearing outcomes shall satisfy the Forecast Energy Requirement Demand Quantity. As discussed in Section 6.4.1 above, all elements of equation (FER) are endogenously determined within the co-optimized day-ahead market except for the Forecast Energy Requirement Demand Quantity, which is specified prior to the day-ahead market according to the next-day hourly load forecasts.

- *Additional clarifying language to accommodate new ancillary services.* The second paragraph in new Section III.1.10.8(ii) mirrors the existing second paragraph of Section III.1.10.8(i), and it mostly contains identical, enumerated provisions. The substantive changes between the new and the existing paragraph are: the wording in item (5) has been generalized to account for ancillary services more broadly, in order to accommodate the new ancillary services in this filing; and the wording in item (6) expressly notes that the clearing will account for resources' physical operating characteristics. As discussed in Section 4.1, and in greater detail in Section 7.2, the co-optimized market's outcomes are determined subject to resources' physical capabilities (such as their maximum output levels, ramp rates, and such).

- *Limitations*. The final portion of new Section III.1.10.8(ii) contains two technical limitations on the clearing process. The first, in enumerated item (1) in the last paragraph of Section III.1.10.8(ii), is only applicable to generation contingency reserve and replacement energy reserve. We discuss this provision in Section 7.4 of this paper, after we explain those specific new ancillary services. The second, in enumerated item (2) in the last paragraph of Section III.1.10.8(ii), is a limitation on energy imbalance reserve awards to non-fast start resources without day-ahead energy schedules. This is motivated by computational considerations, and we explain this provision and its rationale in Section 6.4.3, next.

In addition, there are general revisions acknowledging that the day-ahead market will be co-optimized in Section III.1.7.6(a), Section III.1.10.2(b), Section III.2.1, and Section III.2.2, where such were necessary for consistency with the new co-optimized clearing provisions in Section III.1.10.8.

Last, new Section III.3.2.1(a)(2)(vi) states that energy call option offers that are cleared and contribute to satisfying the Forecast Energy Requirement Demand Quantity will receive a Day-Ahead Energy Imbalance Reserve Obligation. (Note that the term "Obligations" as used in this portion of the Tariff refers to quantities for settlement, and are units of MWh, not dollars).

The language used in new Section III.3.2.1(a)(2)(vi) reflects the market design attribute that market participants' energy call option offers are the *inputs* into the co-optimized day-ahead market clearing process, and the different ancillary service products (*i.e.,* obligations) are the *outputs* of the market clearing process (*see* Section 4.1).

► **Pricing provisions.** The pricing provisions for the new ancillary services are primarily contained in new Section III.2.6.2. Here, we summarize those provisions specifically related to incorporating energy imbalance reserve and the forecast energy requirement into the day-ahead market. (The corresponding provisions related to generation contingency reserve and replacement energy reserve are discussed separately, in Section 7.4). Specifically:

- Section III.2.6.2(a)(vii) defines the Forecast Energy Requirement Price. Consistent with the economic explanations in Section 6.2 and 6.3 of this paper, this price it is calculated as the marginal cost to satisfy the next increment of the Forecast Energy Requirement Demand Quantity. (On this, *see also* Section 6.4.3 below, under 'Pricing Notes').

- Section III.2.6.2(a)(vi) assigns the clearing price for energy imbalance reserve to be the Forecast Energy Requirement Price, explicitly. This is consistent with the rationales and explanations for this property in Sections 6.2 and 6.3, above.

- Section III.2.6.1 has a new addition to the existing Locational Marginal Price provisions to enable the day-ahead LMP to properly account for the impact of the (marginal) cost of energy imbalance reserve on the day-ahead LMP, as illustrated in Example 3-B above. Sections III.2.2. and III.2.2(a) also contain general revisions for the same purpose.

  Note that the revised provisions in Section III.2.6.1 are not structured specific to energy imbalance reserve, but cover all of the new Day-Ahead Ancillary Services. This is because the costs of other ancillary services, generation contingency reserve and replacement energy reserve, can also impact the calculation of the day-ahead LMP. We explain this below in Section 7 of this paper.

6.4.3 Technical Notes on Certain Tariff Provisions

In the Tariff, certain provisions are primarily technical in nature, or require technical explanations. In this section, we provide further explanation and rationale for three such provisions of the instant filing. These concern: additional clarity on the Forecast Energy Requirement Price in new Section III.2.6.2(a)(vi); a clearing limitation on energy imbalance reserve awards based on computation considerations in new Section I.10.8(a)(ii); and the Reserve Constraint Penalty Factor on the forecast energy requirement in new Section III.2.6.2(b)(vi). We address each in turn below.

► **Technical notes on the Forecast Energy Requirement Price.** In Section 6.2, we explained the key economic logic of the Forecast Energy Requirement Price using supply and demand concepts. The precise interpretation of the Forecast Energy Requirement Price as the marginal cost of satisfying the system's forecast load comes directly from equation (FER) (*see* Section 6.4.1). When equation (FER) holds with equality at the co-optimized market's solution, an incremental change in the load forecast, LF_h, will require an equal incremental change in the MWh cleared from (a combination of) the energy and energy imbalance reserve on the left-hand side of equation (FER). The change in the (dollar-denominated) day-ahead market's solution objective resulting from an incremental change in LF_h (in MWh) measures the marginal cost of satisfying the forecast energy requirement, and sets the Forecast Energy Requirement Price.[112] The new Tariff language defining the Forecast Energy Requirement Price, in Section III.2.6.2(a)(vi), is written to reflect that that price calculation logic precisely.

New Section III.2.6.2(a)(vi) also accommodates the possibility that at the co-optimized market's solution, equation (FER) may hold with *inequality* – that is, the total MWh on the left-hand side may exceed the total MWh on the right. In this case, an incremental change in the load forecast, LF_h, will not require any increase in the total MWh cleared on the left-hand side for equation (FER) to still remain satisfied. When this occurs, the co-optimization will find it most cost-effective (*i.e.,* optimal) to clear zero MWh of energy imbalance reserve. And since no increase in the total MWh of energy from generation or imports is required to satisfy an increase in the load forecast in this situation, the marginal cost of the forecast energy requirement is zero – and therefore so is the Forecast Energy Requirement Price. In other words, if the co-optimized day-ahead market economically clears sufficient generation and net imports such that equation (FER) does not bind at the market clearing solution, the Forecast Energy Requirement Price will be zero.

► **Energy Imbalance Reserve awards and energy schedules.** In new Section I.10.8(a)(ii), there is a technical provision concerning energy imbalance reserve in this section's final paragraph (which is enumerated starting with (2)). The substantive effect of this provision is that in clearing energy imbalance reserve, the co-optimized day-ahead market will only award energy imbalance reserve obligations to resources that either: (i) are also cleared for energy (using a *different* portion of their

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[112] In mathematical terms, this is known as the *shadow price* of the forecast energy requirement constraint; the Forecast Energy Requirement Price is the shadow price of the forecast energy requirement constraint at the co-optimized market's dispatch solution, given the (optimized) unit commitment schedules.

resource's output range) for the same hour of the next day, or (ii) are fast-start resources (which can start in 30-minutes or less during the operating day).

Stated differently, the day-ahead market will not award energy imbalance reserve to a resource that does not have a day-ahead commitment schedule to be online for energy (which would necessarily be at its Economic Minimum output level or higher) for the same hour, *unless* the unit is a fast-start resource.

The reason for this limitation is a computational one. During the technical evaluation of the co-optimization algorithms, the ISO's technical experts determined that without this limitation, the day-ahead clearing algorithm would require a (near) doubling of the number of integer commitment variables to compute a solution. This raised concern that without this limitation, it may not be practical to optimize the market (within the timeframes necessary to administer the market), because the time required to compute a solution increase nonlinearly with integer commitment variables. With this limitation, we can use the same integer commitment variables for both energy and energy imbalance reserve, and this particular computational concern is no longer an issue.[113]

It is important to note that this limitation is not exclusionary. The co-optimized day-ahead market can clear any resource for energy in order to clear energy imbalance reserve on it as well, since both energy and energy imbalance reserve are simultaneously and endogenously determined. Thus, while it is possible that this limitation may preclude a theoretically more efficient market-clearing solution, its practical impact on the market may be quite small.[114]

It is entirely possible that with further technical development work (and as computational technology steadily progresses over time), we may be able to remove this limitation; nevertheless, out of an abundance of caution, we concluded it was prudent to be clear with market participants about the rationale and necessity of this limitation, and to incorporate this limitation in the clearing-related provisions in new Section I.10.8(a)(ii) of the Tariff.

► **Reserve Constraint Penalty Factor for the forecast energy requirement.** Reserve Constraint Penalty Factors are an existing feature of the ISO's real-time reserve markets and the Tariff. They serve to limit the costs incurred to procure reserves, and to signal in market prices the value of reserve shortages if they do occur.

More specifically, a Reserve Constraint Penalty Factor serves as a 'cap' on the cost (in $/MWh) that the co-optimized market solution would incur to satisfy a reserve demand quantity. That is, if the "re-dispatch" cost to satisfy a reserve demand quantity exceeds the Tariff-proscribed Reserve Constraint Penalty Factor, then the market will stop short of fulfilling the demand quantity for that type of reserves. In such situations, the Reserve Constraint Penalty Factor will either set (directly)

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[113] For additional information and context, *see* Energy Security Improvements: Market-Based Approaches, Presentation to NEPOOL Markets Committee, dated November 12-13, 2019, available at https://www.iso-ne.com/static-assets/documents/2019/11/a4_a_iso_presentation_energy_security_improvements.pptx, at slides 34-44.

[114] *Id*. at slides 40, 43.

the reserve product's market price, or be used to set (in combination with other reserve products' market prices) the reserve product's price.

Each reserve-related constraint in a co-optimized market, both in the ISO's existing real-time market and in the day-ahead market upon the implementation of the Energy Security Improvements, requires a Reserve Constraint Penalty Factor.[115] For energy imbalance reserve, the relevant Reserve Constraint Penalty Factor is that applied to the forecast energy requirement in equation (FER) (*see* Section 6.4.1). This is because Reserve Constraint Penalty Factors are technically applied to the (exogenous) Demand Quantities that define how much should be procured to satisfy the applicable constraint. There is no separate Reserve Constraint Penalty Factor for the (endogenous) Energy Imbalance Reserve Demand Quantity, as its maximum 'cost cap' will be handled by the Reserve Constraint Penalty Factor for the forecast energy requirement.

The forecast energy requirement is a new type of constraint, and requires a new Reserve Constraint Penalty Factor value. In determining this value, our primary economic consideration is the relative value of a shortage of energy imbalance reserve, relative to the other day-ahead ancillary services that are simultaneously procured in the co-optimized day-ahead market (namely*.,* generation contingency reserves and replacement energy reserves).

Put simply, the forecast energy requirement results in the day-ahead market procuring energy imbalance reserves to satisfy the *expected* real-time load in the New England Balancing Authority Area during the applicable hour of the next day. In contrast, the other day-ahead ancillary services are primarily intended to prepare the system, on a day-ahead basis, to be able to respond to contingencies or other *unexpected* events during the operating day – which may, or may not occur. For these reasons, it is economically appropriate that the maximum cost that the co-optimized market will incur to satisfy the forecast energy requirement should be greater than the maximum cost to procure the other ancillary services. Stated simply, the market-clearing should prioritize being prepared to satisfy the real-time load that is expected (*i.e.,* forecast) to occur, over procuring other reserve products for contingencies that may not occur.

This logically implies that the Reserve Constraint Penalty Factor for the forecast energy requirement should be a higher numerical value than the Reserve Constraint Penalty Factors used for the other ancillary services procured in the co-optimized day-ahead market. And indeed, the values filed with the Energy Security Improvements will satisfy this property, for the foregoing reasons.

However, there is another, more technical dimension to this logic as well. The other types of day-ahead ancillary services (generation contingency reserve and replacement energy reserve) are designed with a 'nested' structure: faster-ramping reserve products are able to meet the demand both for fast-ramping capability as well as the demand for slower-ramping capability. For example, Day-Ahead Ten-Minute Generation Contingency Reserve is able to satisfy not only the Day-Ahead Ten-Minute Reserve Demand Quantity, but also the Day-Ahead Thirty-Minute Reserve Demand

[115] As a technical matter, all reserve constraints also require a Reserve Constraint Penalty Factor to ensure there is a mathematically feasible solution to the co-optimization. That technical observation does not guide the choice of a numerical value for the Reserve Constraint Penalty Factor, which is the issue at hand.

Quantity, the Day-Ahead Ninety-Minute Reserve Demand Quantity, and the Day-Ahead Four-Hour Reserve Demand Quantity. And, correspondingly, the market prices for each of these product also 'nest' – a property known as *price cascading*: the market price of a faster-ramping reserve product is always greater than (or equal to) the price of the next slower-ramping reserve product. (For more details, *see* Section 7.2.3).

As applicable to Reserve Constraint Penalty Factors, this means that to prioritize the forecast energy requirement over all other day-ahead ancillary services, it is not sufficient to set the Reserve Constraint Penalty Factor to (just) be the highest value of them all. Rather, the Reserve Constraint Penalty Factor for the forecast energy requirement must be set higher than the *sum* of all other ancillary services' Reserve Constraint Penalty Factors.[116] In this way, if there are insufficient energy call option offers to satisfy both the forecast energy requirement and all other day-ahead ancillary services demand quantities, the co-optimized market solution will signal a shortage of the other ancillary service products first, and a shortage of the forecast energy requirement last. That is, the market-clearing software will prioritize being prepared to satisfy the real-time load that is expected (*i.e.,* forecast) with energy and energy imbalance reserve, relative to the other day-ahead reserve products for contingencies that may not occur. And that is the intended prioritization outcome, if such a situation were ever to be necessary.

In the Tariff, this is implemented by specifying the Reserve Constraint Penalty Factor for the Forecast Energy Requirement Demand Quantity by formula, or reference, to all *other* day-ahead ancillary service Reserve Constraint Penalty Factor values. Specifically, new Section III.2.6.2(b)(vi) stipulates that the Reserve Constraint Penalty Factor for the Forecast Energy Requirement Demand Quantity will be set at 101 percent (that is, just above) the sum of all other day-ahead ancillary service Reserve Constraint Penalty Factor values (which, for convenient reference, are listed in Sections III.2.6.2(b)(i) - (vi)).

Doing the math, the Reserve Constraint Penalty Factor for the Forecast Energy Requirement Demand Quantity is $2,929/MWh.[117] However, the reasonableness of this value rests not on this number in isolation; rather it rests upon: (a) the foregoing logic that it is appropriate to prioritize the forecast energy requirement (that is, energy and energy imbalance reserve) over other forms of day-ahead reserves; and (b) the numerical values of the Reserve Constraint Penalty Factors for those other forms of reserves. (For details on the latter, *see* Section 7.4).

Last, a reality check. In order for the Reserve Constraint Penalty Factor for the Forecast Energy Requirement Demand Quantity to set price in the day-ahead market, the day-ahead market would have to have insufficient supply offers (for both energy and energy options *combined*) to cover the *forecast load the next day.* That seemingly rare prospect would be a major event, signaling the system is at significant reliability risk the next day. In such circumstances, it would be economically

[116] This is, specifically, due to the additive (cascading) shadow price structure explained in Section 7.2.3. *See* Table 7-4.

[117] Using the values in Tariff Sections III.2.6.2(b)(i) - (vi), this calculation is: 101% × ($50 + $1500 + $1000 + $250 + $100) = $2,929.

logical for that expected real-time energy shortage to be signaled throughout the region with a very high day-ahead market price.

6.5 Virtual Transactions and the Forecast Energy Requirement

In this section, we address the settlement treatment of virtual transactions in the co-optimized day-ahead market. Our primary point is that virtual supply and demand will continue to be credited and charged (respectively) at the day-ahead LMP, as they are today. That is, virtual supply is not paid the Forecast Energy Requirement Price, and virtual demand is not allocated its cost. We explain the economic logic and rationale for this treatment, and why it is consistent with sound pricing principles.

There is an allocation of a portion of energy imbalance reserve costs to virtual supply, however, on a cost-causation basis. We explain this rationale as well.

► **Concepts: Virtual supply and the energy gap.** As context, it is useful to revisit how virtual supply can impact the day-ahead energy gap in today's energy-only day-ahead market, and the amount of energy imbalance reserve procured in the co-optimized day-ahead market.

Consider again simple example (d) from Section 6.1. There, we assumed the day-ahead market clears 20 GWh of energy demand in total for a particular hour, and that this exactly matches the forecast energy demand of 20 GWh.

In that example, however, not all day-ahead cleared energy supply is from physical supply resources. Specifically, the market cleared 19 GWh from physical supply resources (*e.g.,* generation, Demand Response Resources, and imports), and cleared 1 GWh of virtual supply (Increment Offers). The total day-ahead cleared energy supply is 19 GWh physical supply + 1 GWh virtual supply = 20 GWh. In effect, 1 GWh of virtual supply displaced competing physical suppliers in this day-ahead market example.

Now consider the energy gap between forecast energy demand and day-ahead cleared energy from physical supply resources. There is only 19 GWh of day-ahead cleared energy supply from physical supply resources to meet the 20 GWh of forecast energy demand the next operating day. In today's day-ahead energy-only market, this produces an energy gap of 1 GWh in the system's next day's operating plan:

20 GWh *forecast energy demand* – 19 GWh *cleared physical supply* = 1 GWh *energy gap.*

Today, in developing its next-day operating plan, this would result in the ISO relying upon 1 GWh of resource capabilities that did not clear in the day-ahead market to cover this energy gap. For the reasons explained in Section 2, such resources have inefficiently low incentives to arrange fuel in advance of the operating day, because they receive no day-ahead compensation for doing so. Moreover, if necessary, the ISO would supplementally commit after (that is, outside of) the day-ahead market the additional generation necessary to ensure sufficient resources are available to meet the forecast energy demand the next day.

With the co-optimized day-ahead market, an energy gap that results when virtual supply clears will be covered within the day-ahead market. Assuming (for purposes of this simple example) that the co-optimized market will still clear 19 GWh of energy from physical supply resources, the co-optimized day-ahead market will now procure 1 GWh of energy imbalance reserve in order to satisfy the forecast energy requirement. The energy gap is now covered:

19 GWh *energy from cleared physical supply* + 1 GWh *EIR* ≥ 20 GWh *forecast energy demand*.

In summary, the main points of this simple example are two. First, in the energy-only day-ahead market today, cleared virtual supply can contribute to the energy gap. And second, in the co-optimized day-ahead energy market, energy imbalance reserve will cover (or contribute to covering) that energy gap.

► **Implications.** Viewing this simple example from a broader perspective, it highlights that from the perspective of the costs of preparing and operating a reliable power system, there is a 'hidden' cost associated with virtual supply that is not priced transparently today.

Specifically, virtual supply must be 'replaced' with physical supply in order for the system to have a reliable next-day operating plan. That has a real cost, and that cost has always been present; but it is manifest in the inefficiently low incentives to arrange fuel for the resources that the ISO must rely upon in its next-day operating plan (but did not receive a day-ahead market obligation), as explained in Section 2; or manifest in the cost of supplemental commitments made outside of the market (which contribute to uplift costs); or both.

With a co-optimized day-ahead market with energy and energy imbalance reserve, that 'hidden' cost is now transparently priced. It is reflected in the payments to be made at the energy imbalance reserve price to resources that acquire energy imbalance reserve obligations. These now cover the energy gap when cleared virtual supply offers contributes to insufficient energy clearing from physical supply resources to satisfy the forecast energy requirement.

Logically, it is consistent with cost-causation principles that virtual supply should be allocated the 'replacement cost' the system incurs when virtual supply clears and energy imbalance reserve is procured to replace it. That replacement cost rate is now transparent: it is the energy imbalance reserve price. Accordingly, with the instant filing, a portion of the system's energy imbalance reserve payments will be allocated to cleared virtual supply. We discuss these charge allocation details, and corresponding Tariff provisions, in detail in Section 6.6.4 below.

► **Day-ahead energy settlement rates for virtual transactions.** Apart from energy imbalance reserve, there is another important settlement rate issue. It remains economically appropriate that virtual supply and demand that clears in the day-ahead market will continue to be settled day-ahead at the day-ahead LMP, as they are today – and that virtual supply is not paid the forecast energy requirement price.

Stated more precisely, in prior Sections 6.2 through 6.4 we explain why it is consistent with sound pricing principles that day-ahead cleared energy from physical supply resources will be paid the day-ahead LMP *plus* the forecast energy requirement price. In contrast, as we explain now, day-ahead cleared energy from virtual supply will be paid the day-ahead LMP, and not paid the forecast energy requirement price. This is not discriminatory treatment; far from it, this compensation design reflects the fact that day-ahead energy sales from physical and virtual resources are fundamentally *not* similarly situated with respect to their value in meeting the system's day-ahead forecast energy requirement. We explain this, and why these compensation rates are both economically-appropriate and consistent with sound pricing principles, next.

The participation payment principle. The appropriateness of this treatment of virtual supply is plainly evident from the perspective of the *participation payment principle,* explained earlier in Section 6.2.3. That principle states that a supply offer that participates in (contributes to) satisfying multiple requirements should be paid the price associated with each requirement. In the present context, however, virtual supply does not contribute to multiple requirements; it only contributes to one, and so is paid only one price: the day-ahead LMP.

Stated more precisely:

- The day-ahead LMP is the marginal cost of serving energy demand, and is the price associated with the market clearing requirement in equation (MCR) (*see* Section 6.4.1). Virtual supply comprises the term INC_h in equation (MCR). Cleared virtual supply offers therefore directly participate in – that is, contribute to – satisfying that requirement. Accordingly, cleared virtual supply must be paid the day-ahead LMP.

- The Forecast Energy Requirement Price is the marginal cost of satisfying forecast energy demand, and is the price associated with the forecast energy requirement in equation (FER) (*see* Section 6.4.1). Virtual supply, or INC_h, does not appear in equation (FER) and thus does not count toward total supply on the left-hand side of equation (FER). Cleared virtual supply offers therefore do *not* participate in – that is, do not contribute to – satisfying the forecast energy requirement. Accordingly, cleared virtual supply should not be paid the forecast energy requirement price.

- Similarly, virtual demand, or DEC_h, does not appear in equation (FER) and thus does not count toward total expected energy demand on the right-hand side of formula (FER). Cleared virtual demand offers therefore do not participate in – and do not increase the cost of satisfying – satisfying the forecast energy requirement. Accordingly, cleared virtual supply should not be charged the forecast energy requirement price.

At one level, this represents no change from today: virtual supply that clears day-ahead is paid the day-ahead LMP. In addition, real-time settlement rules remain unchanged. Thus, all cleared day-ahead virtual transactions are still settled at the real-time price. Therefore, the energy market settlement of virtual transactions is unchanged from that in effect today, and no new rules are required.

Marginal-cost pricing principles. In Section 6.2, we emphasized that the pricing and payment rules in the co-optimized day-ahead market with energy and energy imbalance reserve satisfy sound economic principles, in part because they reflect the fundamental principle of marginal-cost pricing. Since virtual supply and physical supply that clear energy day-ahead will be paid different total day-ahead settlement rates for the energy they clear, it is useful to reconcile how those different total payment rates are *both* consistent with marginal-cost pricing.

The core insight is that there are different marginal costs of serving day-ahead demand with virtual supply offers, versus serving day-ahead demand with physical supply offers. The difference is the cost of the energy imbalance reserve required with the former, but not required – indeed, avoided – with the latter. Those different marginal costs line up precisely with the different total settlement rates to be paid to virtual supply and paid to physical supply that clear in the co-optimized day-ahead market.

Consider the change in the system's costs, at the margin, if a participant offered incrementally more cleared (infra-marginal) virtual supply. If the day-ahead market's energy supply offer at the margin is from a physical resource, the incremental virtual supply would save the system the marginal cost of energy supply from that physical resource. From Section 6.2, that is equal to:

MC of energy supply = DA LMP + FERP

(where FERP is the forecast energy requirement price). *See* again Figure 6-3.

However, clearing incremental virtual energy supply in lieu of the marginal physical resource's energy supply would result in the need to also procure incremental energy imbalance reserve to satisfy the forecast energy requirement. The marginal cost of that incremental energy imbalance reserve must be accounted for. The total reduction in the system's costs, at the margin, with an increment of cleared virtual energy supply is therefore the difference between the marginal cost of energy supply and the marginal cost of energy imbalance reserves:

MC of energy supply (an avoided cost) – MC of EIR (an incurred cost)

which, combining both of these formulas, is:

DA LMP + FERP – EIR Price.

Here, as always, the Forecast Energy Requirement Price equals the energy imbalance reserve price. Thus the reduction in the system's costs, at the margin, when there is incrementally more cleared virtual supply is simply the day-ahead LMP. Thus, the proper marginal-cost based payment rate to virtual supply is the day-ahead LMP.

The main point here is important. It is consistent with sound economic principles that the day-ahead market's payment rate for virtual transactions is the day-ahead LMP, as it is today. That is, virtual supply is not paid the Forecast Energy Requirement Price, and virtual demand is not allocated its cost. However, for the reasons discussed above, a portion of energy imbalance reserve costs are allocated to virtual supply, on a cost-causation basis.

6.6 Settlements and Cost Allocation

Sections 6.2 through 6.5 explained the economic logic and principles for the settlement rates associated with the forecast energy requirement and energy imbalance reserve. In this section we summarize their cost allocation and its rationale. In addition, below we provide additional explanation of the new Tariff provisions governing these settlement and allocation rules.

6.6.1 Forecast Energy Requirement Credits

The payment of the Forecast Energy Requirement Price to physical supply resources that clear energy in the day-ahead market is provided in new Section III.3.2.1(q)(5) of the Tariff, and is called the Forecast Energy Requirement Credit.

These Forecast Energy Requirement Credits are paid to Generator Assets, Demand Response Resources (which participate as "supply" in the energy markets), and import External Transactions. These resource types correspond with the types of supply that contribute to – that is, participate in – the forecast energy requirement as shown in equation (FER) in Section 6.4.1.

Note that there exists no real-time analog to the Forecast Energy Requirement Price. Put differently, there is no separate 'forecast *in* real-time' of 'demand *in* real-time'; there is only one real-time demand – the actual system load. This means there is no 'close-out' or deviation charges associated with the Forecast Energy Requirement Credit, as there is when a market participant's real-time energy differs from its day-ahead cleared energy. The real-time settlement for deviations from a participants' day-ahead energy obligation is at the real-time LMP (which is not altered in this filing). *See, e.g.,* cases (i) and (j) in Section 4.3.2.

6.6.2 Forecast Energy Requirement Cost Allocation

The cost allocation of the Forecast Energy Requirement Credit is provided in new Section III.3.2.1(q)(6) of the Tariff, and is called the Forecast Energy Requirement Charge.

These costs are allocated primarily to the system's real-time load, on the 'beneficiaries-pay' principle. The reasoning is that the forecast energy requirement exists to ensure the power system is prepared to reliably deliver energy to load *in real-time*. Real-time load is, therefore, ultimately the beneficiary of the costs incurred to satisfy the system's forecast energy requirement.

There are two exceptions of note:

- New Section III.3.2.1(q)(6)(i) provides that cleared day-ahead export External Transactions will be charged a rate equal to the Forecast Energy Requirement Price. These are the only *day-ahead* energy obligations subject to the Forecast Energy Requirement Charge.

  The reason for this treatment is that day-ahead exports are *not* included in the ISO's load forecasting process. Rather, the total MWh of cleared day-ahead exports are accounted for separately in the forecast energy requirement (*see* equation (FER) in Section 6.4.1). Their separate accounting in the forecast energy requirement constraint in the co-optimized day-ahead market means that each additional MWh of day-ahead cleared exports has a direct, cost-causative impact on the total Forecast Energy Requirement Credit. That is, an increment of cleared MWh of day-ahead exports requires an incremental MWh of either energy from physical supply resources, or of energy imbalance reserve, to be procured to satisfy the forecast energy requirement. Thus, day-ahead cleared exports are charged the Forecast Energy Requirement Price.

Note further that this treatment means if a market participant clears both day-ahead imports and day-ahead exports for the same hour (possibly on different external interfaces), they will receive either a net credit or charge for their *net* external transaction MWh. That netting outcome is economically desirable, to avoid distorting external transaction scheduling incentives (which could otherwise occur if exports and imports were charged and credited at different payment rates for the same hour).

- New Section III.3.2.1(q)(6)(ii) contains an exclusion from the Forecast Energy Requirement Charge for the real-time load of storage resources (*i.e.,* the energy consumed in real-time for charging). In the Tariff, storage resources are known as Storage DARDs (short for Storage Dispatchable Asset-Related Demands).

  The reasons for this exclusion are two. First, the ISO's load forecast does not include real-time load used by energy storage resources. Thus, the forecast energy requirement in constraint (FER) is not being enforced on their behalf, as it is for the (firm) load that is being forecast by the ISO in the New England Balancing Authority Area. The second reason is to avoid inefficiently distorting storage resources' charging behavior in the real-time energy market. If, counterfactually, storage resources' real-time loads were subject to the Forecast Energy Requirement Charge, then the effective price the storage resource would face for its real-time load would not be the real-time LMP, but instead would be a higher effective price – incorporating the additional (per-MWh) cost it would incur for its share of the Forecast Energy Requirement Charge. That higher effective charging price would create unintended, inefficient consequences in the real-time energy market, inasmuch as energy storage resources' real-time charging decisions would no longer be based on the system's real-time marginal cost of energy.

6.6.3 Energy Imbalance Reserve Credits and Charges to Sellers

Recall that market participants with cleared energy call option offers have two settlements associated with their energy call options. The first is a credit, at the market clearing price of the ancillary service product for which the energy option was cleared. The second is a charge, or the option close-out, which is at the maximum of the real-time LMP less the strike price, or zero. *See* examples (a) through (j) in Section 4.3.

The new Tariff provisions provide that each MWh of a seller's cleared energy imbalance reserve will receive a payment at the day-ahead clearing price for energy imbalance reserve, and the corresponding option close-out charge.

- New Section III.3.2.1(a)(2)(vi) stipulates that market participants with cleared energy call option offers that contribute to satisfying the forecast energy requirement receive a Day-Ahead Energy Imbalance Reserve Obligation.

- New Section III.3.2.1(q)(1)(vi) provides for the seller's credit. It stipulates that each MWh of Day-Ahead Energy Imbalance Reserve Obligation will be paid the clearing price for Day-Ahead Energy Imbalance Reserve Obligation.

- New Section III.3.2.1(q)(2)(ii) provides for the seller's option close-out charge. It stipulates that each MWh of Day-Ahead Energy Imbalance Reserve Obligation will be charged the energy option close-out amount. The option close-out amount is based on the Real-Time Hub Price and the energy option strike price, as explained in Section 4.3.2 (on option settlement location) and Section 4.5.2 (on strike prices).

  As a Tariff drafting note, provisions (i) and (ii) of new Section III.3.2.1(q)(2) are written separately for generation contingency reserve and replacement energy reserve in (i), and for energy imbalance reserve in (ii), solely for purposes of separate cross-referencing of (i) and (ii) from other portions of the Tariff.

6.6.4 Energy Imbalance Reserve Cost Allocation and 'Close-Out' Offsets

► **Concepts and rationales.** Like the energy imbalance reserve credits and charges to sellers, the energy imbalance reserve cost allocation has two components. One is the cost allocation (a charge) associated with the day-ahead energy imbalance reserve price paid to sellers. The second is the close-out offset (a credit) associated with the close-out of seller's day-ahead energy options.

From a broader perspective, these two components are the 'opposite' side of an energy call option seller's position. Conceptually, (most) market participants that are allocated the costs of the energy call options are effectively receiving a 'hedge' against the real-time LMP. They pay the clearing price for the energy call option; and by doing so, they receive a hedge at the energy call option strike price for their real-time price exposure. (For additional discussion, see Frequently-Asked Question 7 in Section 6.2.4, above.)

In developing this cost allocation for energy imbalance reserve, we sought to allocate these costs on a $/MWh basis that mirrors the $/MWh basis that sellers receive for their energy imbalance reserve credits/charges. That is, the cost allocation rules do not simply divide the total costs to be allocated among the MWh to which they will be allocated on a pro-rata basis. Rather, they seek to line up the cost-allocation rate with the credits-to-sellers rate. This is in keeping with the design intent that an energy call option's cost allocation reflects the opposite side of the energy call option seller's position.

The primary cost allocation for energy imbalance reserve is based on: (a) a market participant's real-time load in excess of its day-ahead cleared energy purchases, in MWh; and (b) a market participant's virtual supply offers cleared day-ahead, in MWh (which are equal to those offers' real-time deviations, by the nature of virtual supply). The reasoning for energy imbalance reserve cost allocation to these deviations is based on cost-causation. Specifically:

a) For load deviations, the reasoning is that if these market participants' had procured energy day-ahead instead of waiting to procure energy only in real-time, then (on average) the system's energy gap would be smaller and less energy imbalance reserve would be procured. We say 'on average' because the load forecast is accurate on average (*see* Section 6.4.1).

b) For virtual supply, the reasoning is the cost-causation explanation in Section 6.5 above.

Finally, there can be situations in which the market's total cleared energy imbalance reserve MWh is larger than the total MWh of deviations in (a) and (b) combined. In such cases, there will be some "residual" energy imbalance reserve costs to be allocated, after allocating the applicable credits/charges to the deviations in (a) and (b) above. The residual costs to be allocated will flow to real-time load obligations, on a beneficiaries-pay basis.

► **Corresponding Tariff provisions.** The cost allocation provisions for energy imbalance reserve are contained in new Section III.3.2.1(q)(4). Deviations-based cost allocations are difficult to specify precisely in words, so there are multiple parts:

- Section III.3.2.1(q)(4)(i) defines the relevant load deviations. Note that deviations related to the energy purchased by Storage DARDs is excluded from this allocation, for the same reasons discussed in Section 6.6.2 above.

- Section III.3.2.1(q)(4)(ii) allocates the cost of payments to sellers of energy imbalance reserve. This is in three parts:

  The second paragraph in that new subsection covers the case where the market's total cleared energy imbalance reserve MWh is larger than the total MWh of deviations; in this case, the costs are allocated to load deviation MWh (as that term is defined in Section III.3.2.1(q)(4)(i)) and to virtual supply MWh on a $/MWh basis, and the residual costs remaining are allocated to real-time load.

  The third paragraph covers a case where the market's total cleared energy imbalance reserve MWh is smaller than the total MWh of deviations; in this case, the costs are allocated to virtual supply MWh on a $/MWh basis because there is a one-to-one relationship between virtual supply and additional cleared energy or energy imbalance reserve from physical supply resources (*see* Section 6.5). The residual costs are allocated to the remaining load deviation MWh (as that term is defined in Section III.3.2.1(q)(4)(i)) on a pro rata basis.

  The fourth and final paragraph covers the case where there are no load deviation MWh (as that term is defined in Section III.3.2.1(q)(4)(i)), so all costs are allocated to virtual supply MWh on a $/MWh basis.

- Section III.3.2.1(q)(4)(iii) allocates the credits resulting from the energy call option close-out charges (the close-out charges being paid by the sellers of energy imbalance reserve, as discussed with respect to Section III.3.2.1(q)(2)(ii) in Section 6.6.3). This section is again in three parts, structurally matching the corresponding three parts in Section III.3.2.1(q)(4)(ii).

7. Generation Contingency Reserves and Replacement Energy Reserves

In this section, we provide design detail for the new day-ahead generation contingency reserve and replacement energy reserve ancillary services. We address their purpose, explain their inter-related product structure, and provide historical data to inform the quantities demanded for these day-ahead ancillary services. We also provide numerical examples of co-optimized day-ahead market clearing with generation contingency reserve and replacement energy reserve, in order to illustrate their pricing properties.

7.1 Purpose

With the addition of energy imbalance reserve, the day-ahead market under the Energy Security Improvements will prepare the system to meet the *expected* (that is, forecast) supply and demand conditions during the next operating day. In practice, actual supply and demand conditions during the operating day may differ, for a number of possible reasons. These include unexpected generation derates and outages, weather changes that cause unanticipated increases in energy demand relative to forecast, and so on.

Broadly, the purpose of day-ahead generation contingency reserve and replacement energy reserve is to provide a margin for such uncertainties. With these products, the day-ahead market will help provide a next-day operating plan to reliably supply energy when operating conditions unexpectedly deviate from those forecast day-ahead.

At a high level, generation contingency reserve is a set of ancillary service products designed to prepare the system to be able to successfully respond to sudden, unanticipated energy supply loss during the operating day. When that occurs, the system requires fast-ramping / fast-start response capabilities 'at the ready' in order to promptly close the resulting gap between energy supply and demand (consistent with the timeframes established in applicable reliability standards). With these Energy Security Improvements, these response capabilities will now be procured in the co-optimized day-ahead market.

Replacement energy reserve is a set of ancillary service products designed to prepare the system to handle an unanticipated loss of supply, or unanticipated increase in demand, that persists for a significant (multi-hour) period of time during the operating day. In practice, following an unanticipated loss of a resource scheduled day-ahead to supply energy, the system can use the energy from generation contingency reserve for only a limited period of time; those fast-start / fast-ramping capabilities must be restored to reserve (that is, non-energy producing) status, in sufficient amounts to withstand the *next* possible contingency, within prescribed time limits. After that point, the system requires replacement energy to cover the unanticipated gap in the operating plan's supply-and-demand balance through the remainder of the day.

On the demand side, the system also requires replacement energy to serve *unexpected* increases in energy demand, relative to the day-ahead forecast. If the system has insufficient replacement energy to cover an unexpected increase in energy demand – in effect, to compensate for error in the day-ahead load forecast[118] – the system can suffer from a problem known as the *cannibalization of reserves*. This occurs because (with rare exception) serving unexpected increases in energy demand during the operating day takes priority over maintaining reserve. To do so, the system will dispatch resources for energy as needed, at the expense of the system's reserve capability.

In general, the system's real-time dispatch will seek to preserve its faster-ramping capabilities for real-time contingency response in such situations, so the cannibalization problem results in having less capability to restore contingency reserves to reserve status should an unanticipated supply loss occur. To avoid this cannibalization problem, under the Energy Security Improvements, the day-ahead market will procure replacement energy reserve quantities to cover for both the potential loss of supply from the system's largest day-ahead scheduled resource through the balance of the day, and to cover for unanticipated increases in energy demand (that is, above the day-ahead forecast).

As noted at the outset of this paper, New England's existing energy-only day-ahead market does not procure, or compensate for, generation contingency reserve or replacement energy reserve. Instead, presently the ISO employs unpriced constraints in its day-ahead market unit commitment process to help ensure these capabilities will be available, and it employs out-of-market procedures and reliability-commitment tools (after the day-ahead market) to evaluate the system's preparedness to handle uncertainties the next operating day.[119] But as discussed previously, these out-of-market practices are increasingly problematic.

Generation contingency reserve and replacement energy reserve are inherently needed to address *unanticipated* system events – and, as a result, the resources the ISO relies upon in its next-day operating plan for these capabilities typically have no reason to *expect* to run (or, for those with a day-ahead energy schedule, no reason to expect run above, or for longer than, that day-ahead schedule). As discussed in detail in Section 2.7 earlier, for that reason and others, the resources that provide these essential reliability services presently face inefficiently low market incentives to arrange energy supplies in advance of the operating day – even when such arrangements would be a cost-effective means to reduce reliability risks from society's perspective. As a result, the ISO is increasingly concerned that if the system experiences unexpectedly high demand, an unanticipated, extended supply loss, or both – particularly if it occurs when renewable resources' production capability is low (when the sun is down or the winds are calm) – the region may not have the energy needed to reliably fill the ensuing energy gap.[120]

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[118] This is in contrast to energy imbalance reserve, which seeks to address the gap between the amount of physical supply procured day-ahead and the forecast. Replacement energy reserve is aimed at addressing gaps that arise where the forecast itself is inaccurate.

[119] *See* Brandien Testimony at pp. 17-21; *see also* Section 2.6.1, 2.7 above.

[120] *See,* generally, Brandien Testimony at pp. 23-26.

To better address these concerns, upon implementation of the Energy Security Improvements, the co-optimized day-ahead market will procure generation contingency reserve and replacement energy reserve as new day-ahead ancillary services. At a high-level, the design provides the ISO with the option to "call" on the energy of a day-ahead seller of these ancillary services during the operating day, above and beyond its day-ahead energy schedule (whether or not it has one), in amounts and over timeframes that are designed to match the reliability standards detailed in the accompanying Brandien Testimony.[121]

Each new day-ahead ancillary service will be procured at a uniform and competitively-determined price, providing ancillary service sellers with greater compensation than they receive for these capabilities today (which, in today's day-ahead market, is zero). Importantly, the settlement of these ancillary services uses the energy call option design, thereby providing – for all the reasons explained in Section 4 and 5 previously – an economically sound solution to the misaligned incentives problem for the resources that provide these services. In this way, the new day-ahead generation contingency reserve and replacement energy reserve ancillary services will better address the region's fuel security concerns – while signaling, through new, transparent prices, the costs of a reliable next-day operating plan.

7.2 Products and Their Demand

Generation contingency reserve and replacement energy reserve comprise a set of day-ahead ancillary services that are expressly time-dependent, in order to match the requirements of existing time-denominated reliability standards. These ancillary service products have a hierarchical, or nested, product structure that is important to how the quantities demanded and their clearing prices are determined. We explain these products, their time-related attributes, and their product structure next.

7.2.1 Product Specifications

Together, generation contingency reserve and replacement energy reserve refer to a set of five distinct resource capabilities. They are differentiated by the response-time requirements for each product.

Generation contingency reserve comprises three day-ahead ancillary service products:

GCR 10 Spin: Day-Ahead Ten-Minute Spinning Reserve;

GCR 10 Non-spin: Day-Ahead Ten-Minute Non-Spinning Reserve; and

GCR 30: Day-Ahead Thirty-Minute Operating Reserve (which may be provided by on- or off-line resources).

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[121] *See* Brandien Testimony at pp. 6-12; *see also* Section 2.6 above.

Replacement energy reserve comprises two day-ahead ancillary service products:

RER 90:	Day-Ahead Ninety-Minute Reserve (which may be provided by on- or off-line resources); and
RER 240:	Day-Ahead Four-Hour Reserve (240-minute reserve, which may be provided by on or off-line resources).

These ancillary service products correspond to resources' ramping capabilities (or, if scheduled to be offline, startup and ramping capabilities), above and beyond their day-ahead market energy schedules (whether or not they have one). For example, a resource's day-ahead 10-minute ancillary service product award depends upon (and is limited by) the resource's 10-minute ramping capability above its day-ahead energy schedule for the hour (or, if scheduled to be offline for the hour, its 10-minute startup and ramping capability); and similarly for the additional products. Indeed, and as explained in greater detail below, the two replacement energy reserve products are natural extensions of the generation contingency reserve products, differentiated by time.

► **Day-ahead reserves are energy options.** The co-optimized day-ahead market will procure, and compensate for, these five resource capabilities with financially-binding awards (*i.e.,* obligations). Conceptually, an ancillary service award provides the ISO with the option to call on the seller's resource's energy "on demand" during the operating day, to be delivered within the timeframe defining each product. A day-ahead ancillary service obligation is financially-binding in that it creates a settlement obligation, as a call option on energy, during the obligation hour in the manner described in Sections 4.2 and 4.3.

The three generation contingency reserve products mirror the three fast-start or fast-ramping capabilities that the ISO presently designates and compensates in its real-time market as operating reserves (namely, Ten-Minute Spinning Reserve, Ten-Minute Non-Spinning Reserve, and Thirty-Minute Operating Reserve). Those real-time designations similarly measure resources' unloaded capability that can ramp up, or startup from an offline state, to deliver additional energy within 10 or 30 minutes.[122]

As noted in Section 4.1, the day-ahead generation contingency reserve product awards will not settle against the real-time prices associated with real-time reserve designations. Rather, day-ahead generation contingency reserve awards will be settled, using the standard options settlement rules, against the real-time price of *energy.* For the reasons explained in Section 5.4, the incentives for resources to arrange more robust energy supply (fuel) arrangements are superior – *i.e.,* more efficient – when day-ahead ancillary service obligations are settled as options on real-time energy, instead of being settled using real-time reserve prices.

► **Product time parameters.** The specific time horizons that differentiate each of these day-ahead ancillary service products are expressly based on existing reliability standards. Specifically, the 10-

[122] The ISO does not designate or compensate 90-minute or four-hour reserves in its real-time markets. *See* footnote 48 above.

minute and 30-minute response capabilities enable the system to be prepared, as part of its next-day operating plan, to meet (among other things) requirements for contingency reserve. As explained in the Brandien Testimony:

- **Ten-minute** reserve serves to meet NERC BAL-002-3 Requirement R1 and NPCC Regional Reliability Reference Directory #5 Requirement R1 (a portion of which must be ten-minute synchronized reserve, under the latter);[123] and

- **Thirty-minute** reserve serves to meet NPCC Regional Reliability Reference Directory #5 Requirement R2.[124]

The 90-minute and four-hour response capabilities enable the system to be prepared, as part of its next-day operating plan, to meet (among other things) requirements for contingency reserve restoration. As further explained in the Brandien Testimony:

- Requirement R.3 of NERC-BAL-002-3 requires the Balancing Authority to "restore its Contingency Reserve to at least its Most Severe Single Contingency" within **ninety minutes** following the end of the Contingency Event Recovery Period;[125] and

- NPCC Directory #5 also prescribes a restoration time for Thirty-Minute Operating Reserve: "A Balancing Authority deficient in thirty-minute reserve for **four hours** . . . shall eliminate the deficiency if possible, or minimize the magnitude and duration of the deficiency."[126]

These resource response capabilities, their associated time dimensions, and their use in contingency reserve deployment and contingency reserve restoration are further explained in the numerical example provided in Section II of the Brandien Testimony.[127]

► **Reserves for load forecast error.** In addition, both NERC and NPCC anticipate that a Balancing Authority's forward-looking load forecasts are subject to error, and anticipate that reserves may be used to address forecast error. Currently, the ISO relies on Operating Reserve to help account for load forecast error.[128]

In this context, it is important to observe that energy imbalance reserve and the forecast energy requirement do not prepare the system for potential load forecast *error.* Rather, they prepare the system to serve the energy demand that is *expected* – that is, the energy demand that is forecast to occur – in each hour of the next operating day. In order for the system's next-day operating plan to be able to reliably satisfy an unanticipated increase in energy demand the next day (while meeting

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[123] *See* Brandien Testimony at pp. 8-9.

[124] *See* Brandien Testimony at p. 9.

[125] Brandien Testimony at p. 11 (emphasis added).

[126] Brandien Testimony at p. 11 (emphasis added).

[127] *See* Brandien Testimony at pp. 13-17.

[128] *See* Brandien Testimony at p. 10.

its contingency-related reserve requirements), the system requires additional reserve capability. That additional capability, in effect, compensates for the potential for error in the day-ahead load forecast.

With respect to preparing the system on a day-ahead basis to account for load forecast error, we expect that replacement energy reserve may provide a lower-cost means to do so than higher-cost day-ahead generation contingency reserves (which, as noted, procure fast-start / fast-ramping capabilities analogous to the real-time Operating Reserves that the ISO presently relies upon to help account for load forecast error).[129] This potential lower-cost solution to addressing load forecast error is possible because in practice, errors in the day-ahead load forecast can become evident many hours in advance of real-time; thus, the longer-lead time replacement energy reserve products may effectively help address it.[130] Thus, the Energy Security Improvements include provisions that enable the ISO to procure and compensate day-ahead ninety-minute and four-hour replacement energy reserve products for load forecast error.[131]

In this way, this suite of day-ahead generation contingency reserve and replacement energy reserve ancillary services will enable the day-ahead market – without "out of market" actions – to satisfy the requirements of a reliable next-day operating plan. And it will provide the resources that the system relies upon for these purposes with the incentives, and economically appropriate compensation, to ensure they have energy supply arrangements in place to operate if needed the next operating day.

7.2.2 Ancillary Service Demands are Specified Cumulatively

From a market design standpoint, there is a second important implication of these time-dimensioned reliability standards. The demand quantities of generation contingency reserve and replacement energy reserve necessary to meet the applicable reliability standards depend on the largest potential energy supply losses, as well as the timeframes specified by those standards. Hence, in the day-ahead market, these ancillary service products' demands are specified cumulatively.

The details are (necessarily) complicated, reflecting the complexity of the standards themselves. But the idea is simple. Instead of expressing in the day-ahead market a demand for each ancillary service product *individually,* we can equivalently express those demands *cumulatively.* Doing so will enable the co-optimized market to serve these demands more cost-effectively, by enabling products to substitute for one another.

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[129] The cases evaluated in the Analysis Group's Impact Assessment consistently show generation contingency reserves have higher clearing prices than replacement energy reserve. This reflects the overall greater supply of the latter in the New England system. *See* Impact Assessment, Table 9.

[130] *See* Energy Security Improvements: Market-Based Approaches, Replacement Energy Reserves (Goal #2): Accounting for Load Forecast Error Discussion, Presentation to NEPOOL Markets Committee, available at https://www.iso-ne.com/static-assets/documents/2020/02/a4_a_ii_esi_rer_goal2_accounting_for_load_forecast_error.pptx, at Slides 13-14.

[131] *See* new Tariff Section III.1.8.5(d)-(e).

► **Example.** Here, an example may help. The Brandien Testimony provides a detailed numerical example with three resources, showing the amounts of contingency reserve and replacement energy required to respond, within the timeframes of existing reliability standards, to an unanticipated energy supply loss event.[132] Table 7-1 below reproduces, in part, the assumptions regarding potential supply loss resources and their sizes that appear in Table 1 in the Brandien Testimony.[133]

Table 7-1. Excerpt from Brandien Testimony Table 1 with Example Assumptions

	Pre-Contingency	**Resource**	**Resource Size (MW)**
[1]	First Contingency Loss	Resource A	1600
[2]	Second Contingency Loss	Resource B	1400
	Post-Contingency	**Resource**	**Resource Size (MW)**
[3]	First Contingency Loss	Resource B	1400
[4]	Second Contingency Loss	Resource C	1300

The discussion of this example in the Brandien Testimony explains, at length, the minimum amounts of contingency reserve and replacement energy required and the timeframes in which they are needed. In Table 7-2, we show the total ancillary service demands that would be used in the day-ahead market for the applicable hour, and the ancillary services capable of satisfying them, under this example's assumptions (as detailed in the Brandien Testimony).[134]

Table 7-2. Day-Ahead Demand Quantity Calculations for Brandien Testimony Example

	Cumulative Demand	**Cumulative MWh**	**Determined by Resource(s)**	**Satisfied by Total DA Awards (MWh) of:**
[1]	Total 10-min	1600	A	GCR10 spin + GCR10 nonspin
[2]	Total 30-min	2300	A + ½ B	GCR10 spin + GCR10 nonspin + GCR30
[3]	Total 90-min	3000	A + B	GCR10 spin + GCR10 nonspin + GCR30 + RER90
[4]	Total 240-min	3650	A + B + ½ C	GCR10 spin + GCR10 nonspin + GCR30 + RER90 + RER240

Here's the logic involved in Table 7-2, and how it aligns the day-ahead market's ancillary service demands with the system's reliability requirements. We take each row in Table 7-2 step by step.

[132] *See* Brandien Testimony at pp. 13-17.

[133] *See* Brandien Testimony at p. 13.

[134] The example in the Brandien Testimony does not illustrate the 10-minute spinning reserve requirement, and as such it is omitted in Table 7-2 here. In practice, a portion of the total 10-minute reserve requirement must be maintained as spinning reserve. *See* Brandien Testimony at pp. 8-10. We account for 10-minute spinning reserve in Section 7.2.3 of this paper.

Day-ahead total 10-minute reserve demand quantity. Row [1] of Table 7-2 shows that the total reserve required to respond within 10 minutes is 1600 MWh, and is determined by the size of Resource A.[135] (Resource A is the largest single potential energy supply loss in this example, as shown in Table 7-1). Thus, on a day-ahead basis, the total demand for reserve that can respond in 10 minutes (or less) would be 1600 MWh. This capability enables the system to ensure that the supply and demand balance (*i.e*., the energy gap) is recovered within 15 minutes of the contingency (as required by NERC BAL-002-3 R.1).[136]

Note that this ancillary service demand for total 10-minute reserve can be met by any combination of *two* distinct day-ahead ancillary service products, as shown in the final column of row [1] in Table 7-2. Specifically, the total 10-minute reserve demand of 1600 MWh will be satisfied by the sum of the day-ahead market's ancillary service awards for GCR 10-minute spinning reserve and GCR 10-minute non-spinning reserve. The market will clear whatever combination of these two ancillary service products that is the most cost effective, taking account of their contribution toward satisfying the other ancillary service demands in this table (as well as the day-ahead energy demand and the forecast energy requirement).

Day-ahead total 30-minute reserve demand quantity. Row [2] of Table 7-2 shows that the total reserve required to respond within 30 minutes is 2300 MWh, and is determined by the size of Resource A plus one-half of Resource B. (Resource B is the second-largest single potential energy supply loss in this example, as shown in Table 7-1). Thus, on a day-ahead basis, the total demand for reserve that can respond in 30 minutes (or less) would be 2300 MWh.

The *incremental* reserve demand within 30 minutes is 700 MWh greater than the reserve demand within 10 minutes (that is, the MWh in row [2] less row [1] is 2300 MWh – 1600 MWh = 700 MWh). This incremental reserve capability enables the system to meet its 30-minute reserve requirement (as required by NPCC Regional Reliability Reference Directory #5 Requirement R2).[137]

From a market standpoint, this ancillary service demand for total 30-minute reserve can be met by any combination of *three* distinct day-ahead ancillary service products, as shown in the final column of row [2] in Table 7-2. Specifically, the total 30-minute reserve demand of 2300 MWh will be satisfied by the sum of the day-ahead market's ancillary service awards for GCR 10-minute spinning reserve, GCR 10-minute non-spinning reserve, and GCR 30-minute reserve. The market will clear whatever combination of these three ancillary service products that is the most cost effective, taking account of their contribution toward satisfying the other ancillary service demands in this table (as well as the day-ahead energy demand and the forecast energy requirement).

Day-ahead total 90-minute reserve demand quantity. Row [3] in Table 7-2 shows the total reserve required to respond within 90 minutes is 3000 MWh, and is determined by the size of Resource A plus the full amount of Resource B. (Resource B is the second-largest single potential energy supply

[135] Reserve resources are expected to be able to sustain their power output for at least one hour, and reserve awards in the (hourly) day-ahead market are denominated in MWh (not MW).

[136] *See* Brandien Testimony at pp. 14-15.

[137] *See* Brandien Testimony at p. 9.

loss in this example, as shown in Table 7-1). Thus, on a day-ahead basis, the total demand for reserve that can respond in 90 minutes (or less) would be 3000 MWh.

The *incremental* reserve demand within 90 minutes is 700 MWh greater than the reserve demand within 30 minutes (that is, the MWh in row [3] less row [2] is 3000 MWh – 2300 MWh = 700 MWh). This incremental reserve capability enables the system to meet its 90-minute requirement to restore its total 10-minute reserves to reserve status (as required by NERC BAL-002-3 R.3).[138]

From a market standpoint, this ancillary service demand for total 90-minute reserve can be met by any combination of *four* distinct day-ahead ancillary service products, as shown in the final column of row [3] in Table 7-2. Specifically, the total 90-minute reserve demand of 3000 MWh will be satisfied by the sum of the day-ahead market's ancillary service awards for GCR 10-minute spinning reserve, GCR 10-minute non-spinning reserve, GCR 30-minute reserve, and RER 90-minute reserve. As noted above, the market will clear whatever combination of these four ancillary service products that is the most cost effective, taking account of their contribution toward satisfying the other ancillary service demands in this table (as well as the day-ahead energy demand and the forecast energy requirement).

Day-ahead total 240-minute reserve demand quantity. Row [4] of Table 7-2 shows the total reserve required to respond within 240 minutes is 3650 MWh, and is determined by the size of Resource A plus Resource B plus one-half of resource C. (Resource C is the post-contingency second-largest single potential energy supply loss in this example, as shown in Table 7-1). Thus, on a day-ahead basis, the total demand for reserve that can respond in 240 minutes (or less) would be 3650 MWh.

The *incremental* reserve demand within 240 minutes is 650 MWh greater than the reserve demand within 90 minutes (that is, the MWh in row [4] less row [3] is 3650 MWh – 3000 MWh = 650 MWh). This incremental reserve capability enables the system to meet the 240-minute standard regarding restoration of the system's total 30-minute reserves (per NPCC Regional Reliability Reference Directory #5).[139]

From a market standpoint, this ancillary service demand for total 240-minute reserve can be met by any combination of *five* day-ahead ancillary service products, as shown in the final column of row [1] in Table 7-2. Specifically, the total 240-minute reserve demand of 3650 MWh will be satisfied by the sum of the day-ahead market's ancillary service awards for GCR 10-minute spinning reserve, GCR 10-minute non-spinning reserve, GCR 30-minute reserve, RER 90-minute reserve, and RER 240-minute reserve. As noted above, the market will clear whatever combination of these five ancillary service products that is the most cost effective, taking account of their contribution toward satisfying the other ancillary service demands in this table (as well as the day-ahead energy demand and the forecast energy requirement).

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[138] *See* Brandien Testimony at pp. 11, 15-16.

[139] *See* Brandien Testimony at p. 16.

► **Implications.** There are two main points to take from the extended example in the Brandien Testimony. First, it exemplifies a general property of the new day-ahead ancillary service design: both the timing, and the quantities to be procured, of the new day-ahead ancillary service products serve to enable the system to satisfy – through the market – existing reliability standards. In that way, they serve to enable the day-ahead market to meet the requirements of a reliable next-day operating plan, while providing the resources the ISO relies upon for these capabilities with stronger incentives to ensure they have energy supply arrangements in place in advance of the operating day.

Second, Table 7-2 shows that instead of expressing in the day-ahead market a demand for each ancillary service product *individually,* we can equivalently express those same demands *cumulatively.* Doing so enables the co-optimized market to count faster-responding ancillary service product awards toward the ancillary service demands applicable over longer timeframes (though not the reverse, as discussed below), improving the design's cost-effectiveness overall. Importantly, this cumulative representation of ancillary service demands is also used in the ISO's existing real-time reserve markets for the reserve products designated by the ISO in real-time, and it has proved to be an effective (if technical) demand representation technique for reserve-energy co-optimization since its inception nearly fifteen years ago.

7.2.3 Product Substitution and Price Cascading

► **Offers and clearing.** As discussed in Section 4.1, market participants that wish to sell day-ahead ancillary services will submit a single energy call option offer for their resource, in addition to the resource's energy supply offer.[140] That is, market participants will not submit separate offers to sell the 10-minute ancillary service products, 30-minute ancillary service product, 90-minute ancillary service product, and so on. The co-optimized day-ahead market clearing process will determine the most efficient (and profitable) assignment of the resource's energy supply offer and its energy call option offer to meet energy demand, forecast energy requirement, and the ancillary service demand quantities. We provide several examples to illustrate the co-optimized day-ahead market's clearing with generation contingency reserve and replacement energy reserve in Section 7.5-7.7 below.

A resource's ramping capability and scheduled on- or off-line status depend on its energy award for the hour. For example, a resource that is economically scheduled to supply energy at its maximum output level in the day-ahead market has no additional capability with which to provide reserve. And an online resource that can ramp quickly may be assigned a lower energy schedule if it is more efficient (and profitable) for the day-ahead market to clear most of its potential production capability for ancillary services. The day-ahead market clearing process, being jointly performed for energy and all ancillary services simultaneously, accounts for these physical resource capabilities and limits.

[140] Regardless of the day-ahead ancillary service product type a seller is awarded, in settlement each MWh of its award will be closed-out at the same Energy Call Option Strike Price. *See* Section 4.3.

► **Incremental capability assignments.** Importantly, in performing this co-optimization, the day-ahead market clearing will account for the physical capabilities of the resource in determining its ancillary service awards. This is done in a manner that assigns a resource's *incremental* ramping capability to products with longer time horizons.

As a simple example, consider a 500 MW resource that clears 200 MWh of energy in the day-ahead market for each hour of the day. Assume this resource has a 1 MW per minute ramp rate. That means it could ramp to an output level of 210 MW in 10 minutes, to 230 MW in 30 minutes, 290 MW in 90 minutes, and 440 MW in four hours (since 200 MW initial output + 240 min in four hours × 1 MW / min ramp rate = 440 MW in four hours).

Assume that this resource submits both energy supply and energy call option offers for all 500 MW of its capacity, and that energy call option offer is economic to clear for all five generation contingency reserve and replacement energy reserve products. Its awards would account for its cumulative ramping capability, but each award will equal its *incremental* ramping capability as shown in the table below.

Table 7-3. GCR and RER Award Example

Time (minutes)	Output (MW)	Incremental Output (MW)	Ancillary Service Award Type
0	200	0	-
10	210	10	GCR 10-min spinning reserve
30	230	20	GCR 30-min reserve
90	290	60	RER 90-min reserve
240	440	150	RER four-hour reserve

In this example, the resource can ramp from its scheduled energy output of 200 MWh. It can increase its power output by 10 MW to 210 MW within 10 minutes, so it would receive (at most) a 10 MWh award for day-ahead GCR 10-minute spinning reserve. It can increase its power output by an *additional* 20 MW (to 230 MW) within 30 minutes, so it would receive (at most) a 20 MWh award for day-ahead GCR 30-minute reserve. It can further increase its power output by an *additional* 60 MW (to 290 MW in total) within 90 minutes, so it would receive (at most) a 60 MWh award for day-ahead RER 90-minute reserve. And, as shown in the last row of Table 7-3, it can further increase its power output by an *additional* 150 MW (to 440 MW in total) within 240 minutes, so it would receive (at most) a 150 MWh award for day-ahead RER four-hour reserve.

Figure 7-1 provides a graphical interpretation of the resource-specific ramping capability and the associated ancillary service product award amounts for the assumptions in Table 7-3.

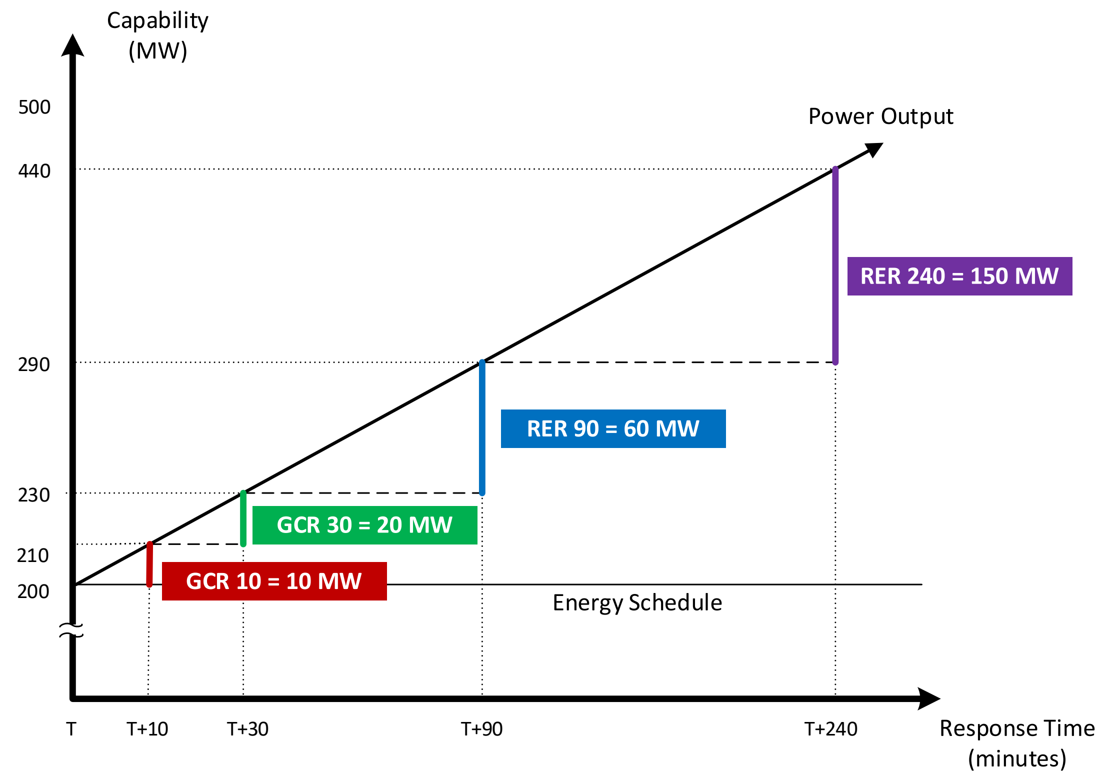


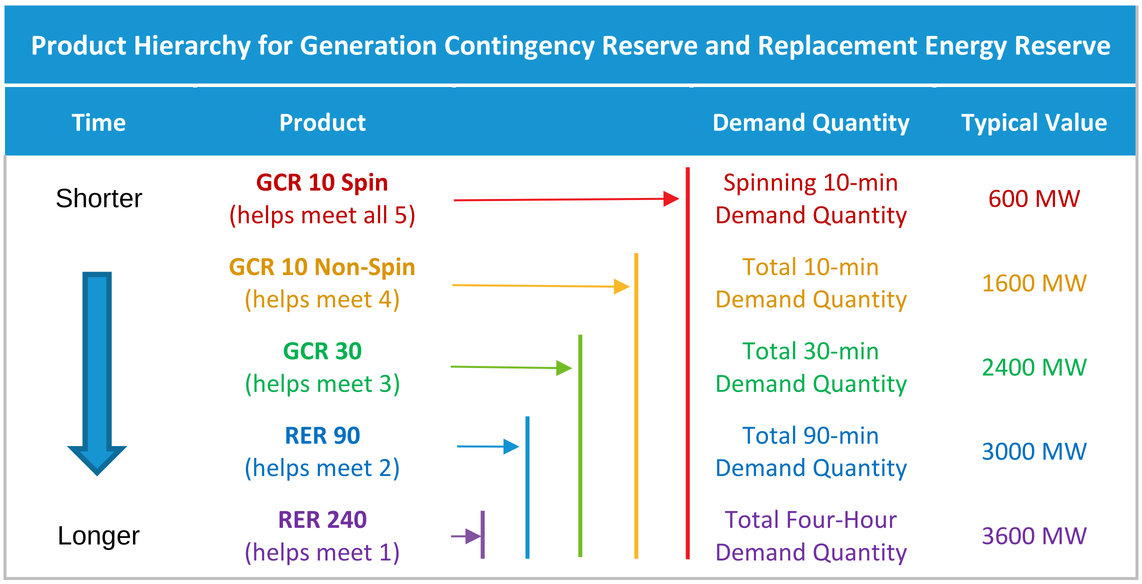
Figure 7-1. Incremental Reserve Awards for the Resource Assumptions in Table 7-3

In this way, the system is not counting the resource's initial 10 MWh of ramping capability toward two different products; that is, the system only counts the resource's *incremental* ramp capability to products with longer time horizons. This incremental capability award accounting system is designed to align well with a central feature of the generation contingency reserve and replacement energy reserve products' design, their product substitution structure. We address this next.

► **Product substitution.** Taken together, the five day-ahead ancillary service products that comprise generation contingency reserve and replacement energy reserve have an important, interdependent structure. In particular, the five generation contingency reserve and replacement energy reserve products are *one-way substitutes.* That means awards for a product with a shorter time horizon can substitute for awards with a longer time horizon in the market clearing process – but not the reverse.

Put differently, a resource's capability that can respond in 10 minutes or less (for example) will also help to satisfy the total demand for 30-minute reserve, and the total demand for 90-minute reserve, and the total demand for four-hour reserve. However, the reverse is *not* true: a resource's capability that can (only) respond within 30 minutes, but not within 10 minutes, does not help to satisfy the demand for 10-minute reserve.

Combining this property with the incremental capability assignment accounting discussed above provides a 'nested', or hierarchical, structure between each generation contingency reserve and replacement energy reserve product and the day-ahead ancillary service demand quantities they help to satisfy. A simple way to visualize this one-way structure of the generation contingency reserve and replacement energy reserve ancillary service products is shown in the graphic below.



In words, this shows that an award of GCR 10-minute spinning reserve contributes to meeting all five of these total day-ahead ancillary service demand quantities in the co-optimized day-ahead market. An award of GCR 10-minute non-spinning reserve contributes to meeting four of these five total day-ahead ancillary service demand quantities; an award of GCR 30-minute reserve contributes to meeting three of these five total timed day-ahead ancillary service demand quantities; and so forth.

To clarify a crucial point: in this graphic, the left-hand slide lists the ancillary service *products*, and the right-hand side lists the multiple *demand* quantities to which they contribute. The demand quantities listed on the right are cumulative, but the individual products on the left are not. In other words, the 1600 MW demand quantity shown for total 10-minute reserve capability (shown in yellow) *includes* the 600 MW demand quantity shown for 10-minute spinning reserve capability (shown in red). And while either the GCR 10-minute spinning reserve *product* or the GCR 10-minute non-spinning reserve *product* can contribute to satisfying the total 10-minute non-spinning reserve *demand*, they are distinct products — and only one, the GCR 10-minute spinning reserve product, can serve the 10-minute spinning reserve demand.

This product substitution structure helps the day-ahead market co-optimize energy and ancillary service costs effectively. In particular, a MWh of the ancillary service capabilities that are typically in relatively less ample supply, such as the fast-responding 10-minute reserve products, can do 'extra duty' by contributing to all five of these ancillary service demand quantities. This tends to reduce the cost to meet all of the system's day-ahead reserve needs to provide a reliable next-day operating plan. As noted previously, the real-time reserve market has used a similar product substitution structure for many years for the reserve capabilities that are designated by the ISO in real-time.

► **Price Cascading.** This product substitution structure has an important implication for pricing. It implies that clearing prices for the ancillary service products with shorter response times will be equal or greater than the clearing prices for the products with longer response times. This property, and the calculation method for these ancillary service product prices, provides the economically-appropriate compensation for each of these five day-ahead ancillary service products.

For example, the clearing price of GCR 10-minute spinning reserve (highest in the hierarchy in the prior graphic) will be greater than or equal to the clearing prices of the four other generation contingency reserve and replacement energy reserve products. And the clearing price of GCR 10-minute non-spinning reserve (second highest in the hierarchy) will be greater than or equal to the clearing prices for the three products associated with longer response times. And so on.

Formally, this property is known as *price cascading*. The economic foundation for this property is the participation payment principle, as discussed earlier in Section 6.3. That principle states that an offer that participates in satisfying multiple requirements should be paid the price (here, as reflected in the marginal cost) of *each* requirement. In this way, the participating offer is compensated for the value it provides, at the margin, by avoiding the procurement of additional (more costly) offers to satisfy each requirement.

Importantly, the price cascading property, and the participation payment principle more generally, are not "double counting" or "double paying" resources for the ancillary services they provide. For example, because of the incremental capability award accounting rules, the additional energy that a resource can deliver (above its day-ahead energy schedule) within 30 minutes, but that it cannot deliver within 10 minutes, does not count toward the demand for total 10-minute reserve. And that incremental GCR 30-minute reserve award is not paid a price applicable to a GCR 10-minute reserve award (which counts toward both the demand for total 10-minute reserve and the demand for total 30-minute reserve).

► **Technical Notes on the Price Cascading.** The new Tariff provisions governing how these day-ahead ancillary service products' clearing prices reflect this price cascading property.[141] To interpret the language in those provisions precisely, here is some additional technical detail.

In the context of generation contingency reserve and replacement energy reserve, each of the five total ancillary service *demand* quantities shown in the product hierarchy graphic above can be interpreted as a requirement, or constraint, for the day-ahead co-optimization process to satisfy. Each of those ancillary service demand quantities will also have a marginal cost. And each of those marginal costs is determined, as usual, by the change in the (dollar-denominated) day-ahead

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[141] *See* revised Tariff Sections III.2.6.2(a)(i) through III.2.6.2(a)(v).

market's solution objective with respect to an incremental change (in MWh) in the corresponding ancillary service demand quantity, at the margin. In technical terms, the marginal cost of each ancillary service demand quantity is commonly referred to as the "shadow price" associated with each constraint.

As usual, these marginal cost calculations (at the day-ahead market's optimal solution) are the basis for each day-ahead ancillary service seller's market compensation. However, each generation contingency reserve and replacement energy reserve product (excepting the last, RER 240) contributes to multiple requirements. Thus, to satisfy the participation payment principle, each successful seller of a specific generation contingency reserve and replacement energy reserve product must be compensated for the (avoided) marginal cost of *each* constraint to which it contributes.

Here's how this is implemented, and how it is reflected in the Tariff. In the clearing process, the day-ahead market determines a shadow price (that is, the marginal cost) associated with each ancillary service demand quantity. In Table 7-4, we list on the left each of the five generation contingency reserve and replacement energy reserve product types. In the middle and far-right columns, the abbreviation 'SP' stands for shadow price and 'CP' stands for clearing price. To ensure that each generation contingency reserve and replacement energy reserve product is compensated for the marginal value it provides by satisfying multiple constraints, the clearing price for each product is set as the *sum* of the shadow prices (that is, the sum of the marginal costs) for *each* constraint to which it contributes.

Table 7-4. Price Cascading of Ancillary Service Products Using the Participation Principle

	Day-Ahead Reserve Product	Clearing Price = Sum of Constraint SPs ($/MWh)	Equivalent to: ($/MWh)
[1]	GCR 10 spin	$SP_{TenSpin} + SP_{Tot10} + SP_{Tot30} + SP_{Tot90} + SP_{Tot240}$	$SP_{TenSpin} + CP_{GCR10}$
[2]	GCR 10 nonspin	$SP_{Tot10} + SP_{Tot30} + SP_{Tot90} + SP_{Tot240}$	$SP_{Tot10} + CP_{GCR30}$
[3]	GCR 30	$SP_{Tot30} + SP_{Tot90} + SP_{Tot240}$	$SP_{Tot30} + CP_{RER90}$
[4]	RER 90	$SP_{Tot90} + SP_{Tot240}$	$SP_{Tot90} + CP_{RER240}$
[5]	RER 240	SP_{Tot240}	CP_{RER240}

For example: the RER 240 reserve product contributes to only one ancillary service demand quantity, the demand for total four-hour reserve. Row [5] of Table 7-4 shows that the clearing price for the RER 240 reserve product will be set by the shadow price, or marginal cost, of satisfying the market's total four-hour reserve demand quantity.

Working up the table, the RER 90 reserve product contributes to exactly two ancillary service demand quantities: the demand for total 90-minute reserve and the demand for total four-hour reserve. Row [4] of Table 7-4 shows that the clearing price for the RER 90 reserve product will be set by the *sum* of the shadow price to satisfy the market's total 90-minute reserve demand quantity and the shadow price to satisfy the market's total four-hour reserve demand quantity (to which it also contributes).

And so on. At the top, the GCR 10-minute spinning reserve spin product contributes to all five ancillary service demand quantities shown here. Row [1] of Table 7-4 shows that the clearing price for the GCR 10-minute spinning reserve product will be set by the *sum* of the shadow prices to satisfy each of the market's five reserve demand quantities listed here (to all of which it contributes).

In the Tariff, these clearing prices are written based on the formulas in the far-right column of Table 7-4. In words, each generation contingency reserve and replacement energy reserve product's clearing price is the sum of (a) the shadow price (that is, the marginal cost) of the ancillary service demand quantity with the same response time, and (b) the clearing price for the next lower (that is, longer response time) product within this product hierarchy. Mathematically, the last two columns in Table 7-4 are equivalent, but the nesting structure is written more succinctly using the format in the last column. The Tariff language is constructed similarly.[142]. While technical, this structure of the Tariff language makes explicit the price cascading property that is essential for proper price formation and compensation for these five day-ahead ancillary services.

► **Summary and Implications.** Viewed from a broader perspective, there are three key points from this pricing discussion. First, the pricing and compensation for generation contingency reserve and replacement energy reserve are based on sound economic principles. They are based on the system's marginal cost to satisfy each ancillary service demand quantity, which in turn is based on a corresponding reliability requirement. Furthermore, the compensation satisfies the participation payment principle when products contribute to satisfying multiple requirements simultaneously.

Second, this pricing method will play an important role – indeed, it is economically essential – to ensure that the day-ahead ancillary service market will properly compensate all sellers for the *inter-product opportunity costs* of providing one product, instead of any other. We will show this using several detailed numerical examples of market clearing and pricing with generation contingency reserve and replacement energy reserve, in Section 7.5-7.7 below.

Last, the price formation logic and calculation method (as summarized in Table 7-4) is also used for the reserve products designated by the ISO in its co-optimized real-time market. The economic theory that underlies it is sound, and the price cascading property that results possesses the intuitively clear property that market prices are higher for faster-ramping products that, inherently, have greater value in preserving system reliability. It is also a pricing method that market participants should find familiar, given its continuous use for reserve-energy co-optimization in the ISO's real-time markets for nearly fifteen years.

7.3 Demand Quantities and Resource Capabilities: Historical Data

In this section, we provide estimates of the demand quantities for day-ahead generation contingency reserve and replacement energy reserve, based on operating data for the New England

[142] *See* revised Tariff Sections III.2.6.2(a)(i) through III.2.6.2(a)(v).

system during 2018 and 2019. We also summarize corresponding data on the nominal capabilities of the generation fleet to meet these ancillary service demands.

► **Demand quantities.** The required demand quantities for generation contingency reserve and replacement energy reserve ancillary services vary hourly, based on the system's next-day generation patterns and external interface schedules (as determined, primarily, in the day-ahead market). To estimate the system's demand for these ancillary services on a day-ahead basis, we evaluated data from the day-ahead market outcomes and next-day operating plans in 2018 and 2019. These data include information on the system's projected real-time Operating Reserve requirements for each hour of the next day, and the system's several largest potential single-source supply-loss contingencies for each hour of the next day. The ISO presently determines these values, on a day-ahead basis, during the penultimate unit commitment phase of the day-ahead market.[143]

Table 7-5 provides summary statistics for the estimated hourly day-ahead ancillary service demand quantities for generation contingency reserve and replacement energy reserve. As noted above, these ancillary service demand quantities are cumulative demands and, other than the first (for 10-minute spinning reserve), can be satisfied by multiple generation contingency reserve and replacement energy reserve products.

Table 7-5. Hourly Day-Ahead Ancillary Service Demand Quantity Estimates

		Estimates Based on 2018 Data				
	Ancillary Service Reserve Demand	**Minimum** (MWh)	**5th Percentile** (MWh)	**Median** (MWh)	**95th Percentile** (MWh)	**Maximum** (MWh)
[1]	Ten Minute Spinning	475	549	666	783	915
[2]	Total 10 Minute	1,447	1,488	1,584	1,810	2,033
[3]	Total 30 Minute	1,992	2,252	2,389	2,656	2,837
[4]	Total 90 Minute	2,330	2,857	2,995	3,419	3,513
[5]	Total 240 Minute	2,664	3,280	3,613	4,042	4,138
		Estimates Based on 2019 Data				
	Ancillary Service Reserve Demand	**Minimum** (MWh)	**5th Percentile** (MWh)	**Median** (MWh)	**95th Percentile** (MWh)	**Maximum** (MWh)
[1]	Ten Minute Spinning	539	554	586	655	754
[2]	Total 10 Minute	1,456	1,496	1,584	1,769	2,038
[3]	Total 30 Minute	2,090	2,264	2,370	2,589	2,878
[4]	Total 90 Minute	2,520	2,873	2,992	3,336	3,589
[5]	Total 240 Minute	2,928	3,322	3,604	3,942	4,223

[143] *See* Day-Ahead Enhancements: Technical Session 1, ISO New England Presentation dated December 5, 2018, available at https://www.iso-ne.com/static-assets/documents/2018/12/20181205-da-enhancements-tech-session-1.pdf, at Slide 29 et seq.

1. Rows [1] of Table 7-5 (one row [1] for 2018 and one row [1] for 2019) indicate the Day-Ahead Ten-Minute Spinning Reserve Demand Quantity, which can be satisfied with (only) the GCR 10-minute spinning reserve product. Consistent with new Tariff Section III.1.8.5(a), the data in this row are based to the system's projected hourly next-day Ten-Minute Spinning Reserve Requirement for the New England Balancing Authority Area. Historically, this value ranges from 31 percent to 50 percent of the system's projected hourly next-day Total Ten-Minute Reserve requirement.[144]

2. Rows [2] of Table 7-5 indicate the Day-Ahead Total Ten-Minute Reserve Demand Quantity, which can be satisfied with (any combination of) GCR 10-minute spinning reserve and GCR 10-minute non-spinning reserve. Consistent with new Tariff Section III.1.8.5(b), the data in this row are based on the projected hourly next-day Total Ten-Minute Reserve Requirement for the New England Balancing Authority Area. That, in turn is based (primarily) on the size of the system's projected largest source-loss contingency.[145]

   In the example from the Brandien Testimony summarized in Section 7.2.2 above, this demand quantity corresponds to the total 10-minute MWh value shown in row [1] of Table 7-2, which is based on the size of the largest contingency in Table 7-1, Resource A.

3. Rows [3] of Table 7-5 indicate the Day-Ahead Total Thirty-Minute Reserve Demand Quantity, which can be satisfied with (any combination of) GCR 10-minute spinning reserve, GCR 10-minute non-spinning reserve, and GCR 30-minute reserve. Consistent with new Tariff Section III.1.8.5(c), the data in this row are based on the projected hourly next-day Minimum Total Reserve Requirement for the New England Balancing Authority Area. That, in turn, is based on the size of sum of the system's projected largest source-loss contingency and one-half of the second-largest source loss contingency.

   In the example from the Brandien Testimony summarized in Section 7.2.2 above, this demand quantity corresponds to the total 30-minute MWh value shown in row [3] of Table 7-2. That is based on the size of the largest contingency in that example, Resource A, plus one-half of the size of the (pre-contingency) second largest contingency, Resource B, shown in Table 7-1.

4. Rows [4] of Table 7-5 indicate the Day-Ahead Total Ninety-Minute Reserve Demand Quantity, which can be satisfied with (any combination of) GCR 10-minute spinning reserve, GCR 10-minute non-spinning reserve, GCR 30-minute reserve, and RER 90-minute reserve. Consistent with new Tariff Section III.1.8.5(d) and NERC standard BAL-002-3 as referenced therein, the data in this row are based on the projected sum of the system's largest and second-largest source-loss contingencies in the next-day operating plan for the New England Balancing Authority Area.

[144] *See* Brandien Testimony at pp. 9-10.

[145] The Total Ten-Minute Reserve Requirement data summarized here also include a non-performance adjustment, consistent with the ISO's Operating Procedures. *See* Brandien Testimony at p. 9.

In the example from the Brandien Testimony summarized in Section 7.2.2 above, this demand quantity corresponds to the total 90-minute MWh value shown in row [4] of Table 7-2. That is based on the sum of the sizes of the two largest contingencies in that example, Resource A and Resource B.

5. Rows [5] of Table 7-5 indicates the Day-Ahead Total Four-Hour Reserve Demand Quantity, which can be satisfied with (any combination of) GCR 10-minute spinning reserve, GCR 10-minute non-spinning reserve, GCR 30-minute reserve, RER 90-minute reserve, and RER 240-minute reserve. Consistent with new Tariff Section III.1.8.5(e) and NPCC Regional Reliability Reference Directory No. 5 as referenced therein, the data in this row are based on the projected sum of the system's largest, second-largest, and one-half of the third-largest source loss contingencies in the next-day operating plan for the New England Balancing Authority Area.

   In the example from the Brandien Testimony summarized in Section 7.2.2 above, this demand quantity corresponds to the total 240-minute MWh value shown in row [5] of Table 7-2. That is based on the size of the largest contingency, Resource A, plus the size of the second largest contingency, Resource B, plus one-half of the size of the third largest contingency (written in Table 7-1 as the post-contingency second contingency loss), Resource C.

As the variation in the hourly data in Table 7-5 indicates, the actual MWh values of each of these ancillary service demand quantities are dynamic – they vary from hour to hour, and day to day. Figure 7-2 below shows the underlying hourly values summarized in Table 7-5, rows [2]-[5], for 2019. The periodic 'upward' spikes correspond to hours when either large generation assets (that constitute a single source-loss) were scheduled to operate at exceptionally high-levels of output, or an external interface transmission (that constitutes a single source loss of supply) was scheduled at unusually high net import levels during the next operating day. The 'downward' drops correspond to periods when one of the system's (three) normally largest contingencies was not scheduled to operate (*e.g.,* a scheduled outage).

The close time-based alignment of the spikes (both upward and downward) in these data reflect that these are cumulative demand quantities. Therefore, an increase in the size of the first-contingency source loss (determining the total 10-minute reserve demand quantity) will increase all others demand quantities as well, and vice versa.

Overall, while these ancillary service demand quantities are dynamic, they are not nearly as volatile as the energy gap data that determine the demand for energy imbalance reserve, as demonstrated in comparison with Figure 6-1 in Section 6.1.2.

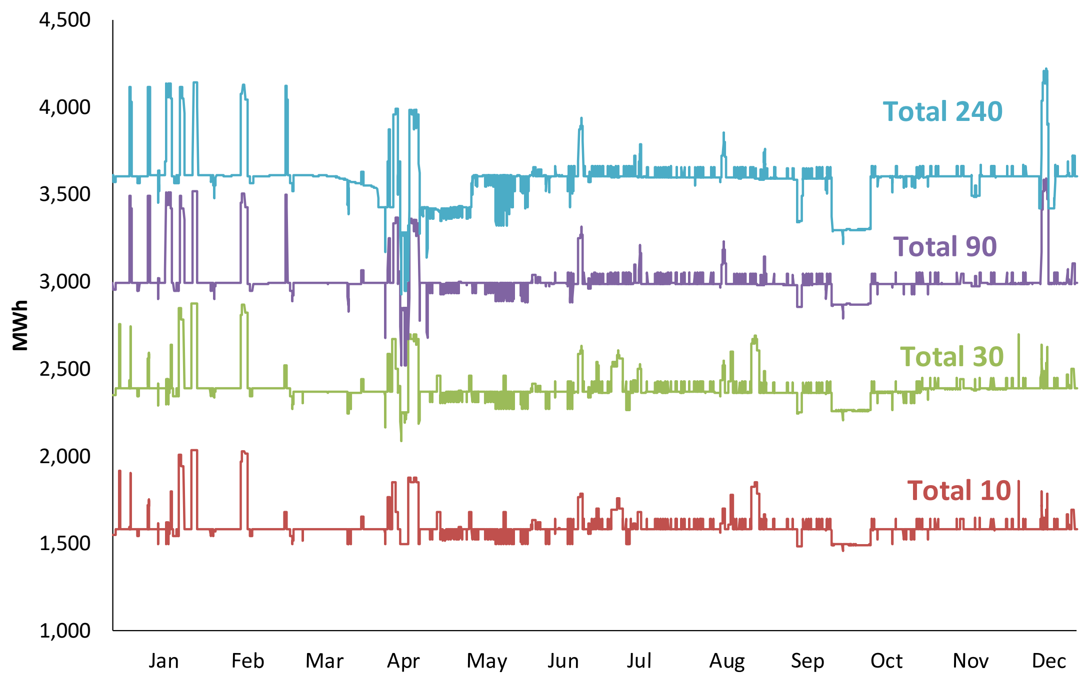

Figure 7-2. Hourly Estimated Day-Ahead Ancillary Service Demand Quantities, 2019

► **Notes and implications.** Two points on these data merit note. First, these ancillary service demand quantities are in addition to the energy imbalance reserve demand quantity needed to satisfy the forecast energy requirement. As noted, energy imbalance reserve serves to meet the system's *expected* (forecast) energy demand; the ancillary service demand quantities for generation contingency reserve and replacement energy reserve serve a wholly different purpose, which is to address *uncertainties* that require additional supplies of energy – that is, in addition to the forecast – in order to operate the system reliably during the next operating day.

Second, the data in Table 7-5 and Figure 7-2 do not include ancillary service demand quantity adjustments to account for load forecast error. In practice, load forecast error is normally comparatively small, relative to the system's overall day-ahead ancillary service demands to address potential supply loss uncertainties (*i.e.,* contingencies) shown above. For example, the mean absolute error of the day-ahead load forecast was just 275 MW and 246 MW in 2018 and 2019, which was just under two percent (as a percent of actual load).[146] Demand quantities to address load-forecast error are most cost-effectively implemented with dynamic calculations, inasmuch as

[146] ISO New England calculations from system operating data.

energy demand uncertainty is greater at certain times of the day and in certain seasons, and can depend on the weather forecasts (*e.g.,* clear skies may present more predictable solar output than intermittently partly-cloudy days, and such). For the total 90-minute and total 240-minute ancillary service demands combined, recent analyses suggest that effective quantity adjustments to account for load forecast error may likely be only a few percent of the value of the load forecast itself.[147]

► **Resource capabilities.** As noted previously, the current energy-only day-ahead market does not procure any of the ancillary services that can satisfy the reliability-based ancillary-service demand quantities shown in Table 7-5 and Figure 7-2. Fortunately, however, the New England system has ample quantities of resources with the ramping capabilities to meet these demands today – that is, if they have fuel to operate when called upon.

Table 7-6 shows the nominal capabilities of all online and offline resources that can satisfy the various ancillary service demand quantities for generation contingency reserve and replacement energy reserve. We use the term 'nominal,' or alternatively the term 'apparent reserve,' because these calculations assume the resources have energy supply arrangements in place to operate (even if they did not expect to be needed that day). More specifically, these data represent the calculated ramping capability, based on resources' physical operating parameters in the ISO's databases, given their actual energy schedules during 2019. We performed these calculations hourly for each resource in the system (during 2019), and summarize the hourly averages in Table 7-6.

The first row is the average energy ramping capability of all units that were offline, evaluated hour-by-hour during 2019, and accounting for their notification and (cold) startup time requirements. The second row is the average energy ramping capability of all units above their day-ahead market energy schedules, evaluated hour-by-hour for 2019, within the timeframes shown.

Table 7-6 Hourly Average Day-Ahead Ramping (Apparent Reserve) Capability, 2019

	State	10-minute	30-minute	90-minute	240-minute
[1]	Offline	3,886	4,897	5,557	6,434
[2]	Online	783	1,079	1,181	1,207
[3]	**Total**	**4,669**	**5,976**	**6,738**	**7,641**

[147] *See* Energy Security Improvements: Market-Based Approaches, Replacement Energy Reserves (Goal #2): Accounting for Load Forecast Error Discussion, Presentation to NEPOOL Markets Committee, available at https://www.iso-ne.com/static-assets/documents/2020/02/a4_a_ii_esi_rer_goal2_accounting_for_load_forecast_error.pptx, at Slides 18-22.

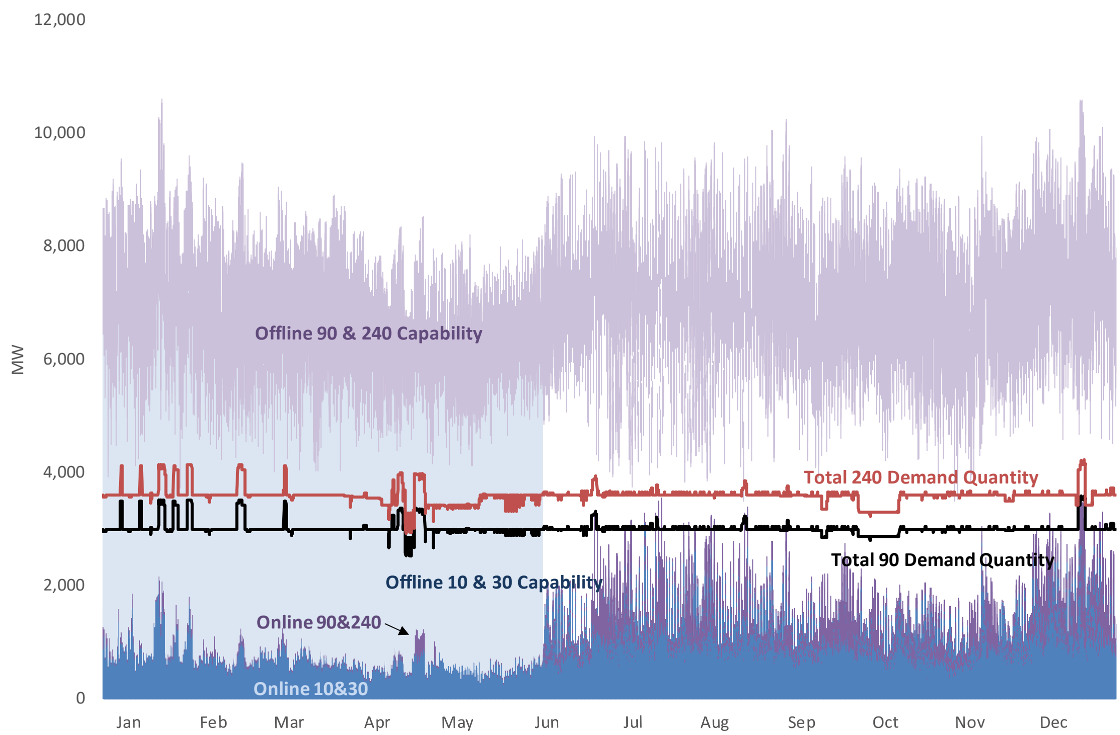

Figure 7-3. Hourly Estimated Day-Ahead Ancillary Service Capabilities, 2019

Overall, these data indicate that the New England fleet's nominal ramping capabilities and capacity amply exceeds the amounts needed to simultaneously satisfy energy demand (as scheduled day-ahead) and to satisfy the new day-ahead ancillary service demand quantities. That observation is more directly evident in Figure 7-3. It shows these same nominal (apparent reserve) capabilities at the hourly level during 2019, superimposed with the total 240-minute and total 90-minute ancillary service demand quantities shown previously in Figure 7-2.

In this figure, the lowest series (in dark blue and purple) show the system's online and unloaded total ramping capability. These values are relatively modest, from 700 MW (for online 10-minute reserve capability) to 1200 MW (for online 240-minute reserve capability), as shown in row [2] of Table 7-6. This reflects, in part, the limited requirement for spinning reserve (as a share of total reserve) in New England (*see* Table 7-5, row [1]). In contrast, the existing generation fleet's ability to provide offline reserve capability is substantial, averaging approximately 5 GW for reserves within thirty minutes and 6.5 GW within four hours (240 minutes), as summarized in row [1] of Table 7-6. These values substantially exceed, normally by a factor of two and often more, the corresponding ancillary service demand quantities.

► **Implications.** The main point of these data is straightforward. In New England, the generation fleet has ample nominal – that is, *apparent* – capability to fully satisfy the system's ancillary service needs and provide for a reliable next day operating plan. However, that capability is of little use if the resources in Table 7-6 have not made the necessary arrangements for fuel in advance of the operating day.

As highlighted in Section 2.7 earlier, the resources that are nominally capable of enabling the system to close an unexpected energy gap frequently have no reason to *expect* to operate the next day, as they are needed precisely when unanticipated events occur. And, also as explained in Section 2, under the current market construct these resources have inefficiently low incentives to make energy supply (*i.e.,* fuel) arrangements in advance of the operating day.

Stated simply, the New England region does not need more generating resources to address its fuel security challenges today. It needs a market appropriately designed to ensure that the resources already here will have strong financial incentives to undertake energy supply arrangements when it would be cost-effective from society's standpoint for the resource to do so. For the reasons explained in Sections 4 and 5, the Energy Security Improvements provide such a market design.

7.4 Tariff Provisions

In this section, we describe various rules governing day-ahead co-optimization of energy and ancillary services, pricing and demand quantities for generation contingency reserve and replacement energy reserve, and their associated new Tariff provisions in this filing.

► **Co-optimization-related new tariff provisions.** The primary day-ahead market co-optimization provisions are contained in new Tariff Section III.1.10.8(a)(ii), revising existing SectionIII.1.10.8(a). These revisions extend the existing energy-only day-ahead market reflected in Section III.1.10.8(a) to a day-ahead market that clears both energy and ancillary services, including generation contingency reserve and replacement energy reserve.

These and related provisions that apply generally to the co-optimization of all new day-ahead ancillary services, with one exception discussed next, are summarized in Sections 6.4.2 and 6.4.3. That discussion applies similarly to the co-optimization for generation contingency reserve and replacement energy reserve.

Limitations. The final portion of new Section III.1.10.8(ii) contains two limitations on the clearing process. The first, in enumerated item (1) in the last paragraph of new Section III.1.10.8(ii), is only applicable to generation contingency reserve and replacement energy reserve (that is, it does not apply to energy imbalance reserve). This limitation requires, by way of reference to existing Tariff Section III.1.7.19.1, that to receive a day-ahead award for generation contingency reserve or replacement energy reserve, a resource must satisfy various technical criteria necessary to provide real-time Operating Reserves. The purpose of this limitation is to ensure that the resources scheduled in the day-ahead market for generation contingency reserve and replacement energy reserve (and that the ISO expects to rely upon in its next-day operating plan to respond as directed in the event of an unanticipated supply loss, as discussed in Section 7.2) meet various pre-existing criteria for real-time reserves related to communications, dispatchability, sustainability, and so forth.

The second limitation in the final portion of new Section III.1.10.8(ii), in enumerated item (2), applies only to energy imbalance reserve as discussed in Section 6.4.2 and, in greater detail, Section 6.4.3.

► **Demand quantities.** For clarity, several new Tariff provisions use the more economically-precise term "Demand Quantity" to reference numerical values that, in more common parlance, are referred to as "requirements." Specifically, new Section III.1.8.5 defines the Day-Ahead Ancillary Service Demand Quantities, consistent with the foregoing explanations in Section 7.2.2. Of note:

- Sections III.1.8.5(a)-(c) define the Day-Ahead Ancillary Service Demand Quantities that can be satisfied by (only) the three generation contingency reserve products. These definitions expressly set the day-ahead market's demand for these three capabilities based on the corresponding projected real-time requirements for Operating Reserves for the same operating hour of the next day. Those, in turn, are determined by the reliability standards applicable to ten- and thirty-minute reserves and described in detail in the Brandien Testimony.[148]

- Section III.1.8.5(d) defines the Day-Ahead Total Ninety-Minute Reserve Demand Quantity. This has two components, one related to unanticipated changes in supply and the other to unanticipated changes in demand. The first component expressly sets the set the day-ahead market's demand for this capability based on the projected requirements to satisfy the NERC BAL-002-3 standard for contingency reserve restoration during the applicable hour of the operating day. That, in turn, is based on the system's (two) largest supply loss contingencies during the corresponding hour, as illustrated above in Section 7.2.3 and described in greater detail in the Brandien Testimony.[149] The second component provides an allowance for load forecast error, for the reasons discussed in Sections 7.1 and 7.2.1 above ("Reserves for load forecast error").

- Section III.1.8.5(e) defines the Day-Ahead Total Four-Hour Minute Reserve Demand Quantity. This has the same two component-structure as the preceding definition, and mirrors that provision with the exception that the associated reliability standard is contained within NPCC Regional Reliability Reference Directory No. 5.[150]

► **Prices and price cascading.** The pricing provisions applicable to GCR and RER are contained in new Tariff Sections III.2.6.2(a)(ii)-(v). These closely match the supporting design details, and reflect the economic logic and rationales, discussed in Section 7.2.3 above.

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[148] *See* Brandien Testimony at pp. 6-17.

[149] *See* Brandien Testimony at pp. 6-17.

[150] *See* Section 7.2.3 and Brandien Testimony at pp. 6-17.

In particular, each price in Sections III.2.6.2(a)(ii)-(v) is determined by the marginal (that is, the incremental) cost of the corresponding Day-Ahead Ancillary Service Demand Quantity, plus the clearing price of the specific Day-Ahead Ancillary Service Demand Quantity that is one step "lower" in the product substitution hierarchy. In this way, the pricing rules expressly and transparently incorporate the price cascading logic described in Section 7.2.3.

Note that each price in Sections III.2.6.2(a)(ii)-(v) is associated with a specific demand quantity, not with a specific generation contingency reserve or replacement energy reserve product. The assignment of prices to product awards is provided for separately in the settlements provisions in new Section III.3.2.1(q)(1), discussed below.

► **Cleared quantities (Obligations).** New Tariff Sections III.3.2.1(a)(2)(i)-(v) govern market participants' cleared quantities of generation contingency reserve and replacement energy reserve, here defined as Obligations ("Obligations" as used in this portion of the Tariff refers to quantities for settlement, and are units of MWh, not dollars).

As a general matter, the language used in new Section III.3.2.1(a)(2) reflects the market design property that market participants' energy call option offers are the *inputs* into the co-optimized day-ahead market clearing process, and the different ancillary service products (*i.e.,* obligations) are the *outputs* of the market clearing process (*see* Section 4.1).

There is a careful accounting of obligations and the product substitution hierarchy in this section to ensure that each Obligation receives the correct payment (the payments being provided in Sections III.3.2.1(q)(1)(i)-(v) and Section III.3.2.1(q)(2)(ii)). This reflects the incremental capability accounting logic and the product substitution hierarchy discussed in Section 7.2.3. Explained directly:

- Section III.3.2.1(a)(2)(i) stipulates that each MWh of an accepted Energy Call Option Offer that contributes to satisfying the Day-Ahead Ten-Minute Spinning Reserve Demand Quantity shall receive a Day-Ahead Ten-Minute Spinning Reserve Obligation. This is the highest product in the generation contingency reserve and replacement energy reserve product hierarchy.

- Section III.3.2.1(a)(2)(ii) stipulates that each MWh of an accepted Energy Call Option Offer that contributes to satisfying the Day-Ahead Total Ten-Minute Reserve Demand Quantity shall receive a Day-Ahead Ten-Minute Non-Spinning Reserve Obligation, *except* it then expressly excludes any MWh that already have a Day-Ahead Ten-Minute Spinning Reserve Obligation. This exclusion is necessary because: (*a*) Day-Ahead Ten-Minute Spinning Reserve, being higher on the product substitution hierarchy, also contributes to satisfying the Day-Ahead Total Ten-Minute Reserve Demand Quantity (*see* Section 7.2.3); and because (*b*) the MWh that receive a Day-Ahead Ten-Minute Spinning Reserve Obligation will be paid the appropriate price, given the price cascading design, for that Day-Ahead Ten-Minute Spinning Reserve Obligation in the settlement provision in Section III.3.2.1(q)(1).

- In a similar manner, Section III.3.2.1(a)(2)(iii) stipulates that each MWh of an accepted Energy Call Option Offer that contributes to satisfying the Day-Ahead Total Thirty-Minute Reserve Demand Quantity shall receive a Day-Ahead Thirty-Minute Operating Reserve Obligation, *except* it then expressly excludes any MWh that already have a Day-Ahead Ten-Minute Spinning Reserve Obligation *or* a Day-Ahead Ten-Minute Non-Spinning Reserve Obligation. This exclusion is necessary because: (*a*) both Day-Ahead Ten-Minute Spinning Reserve and Day-Ahead Ten-Minute Non-Spinning Reserve, being higher on the product substitution hierarchy, also contribute to satisfying the Day-Ahead Total Thirty-Minute Reserve Demand Quantity (*see* Section 7.2.3); and because (*b*) the MWh that receive a Day-Ahead Ten-Minute Spinning Reserve Obligation or a Day-Ahead Ten-Minute Non-Spinning Reserve Obligation will be paid the appropriate price, given the price cascading design, for those awards in the settlement provision in Section III.3.2.1(q)(1).

- The provisions in Sections III.3.2.1(a)(2)(iv) and III.3.2.1(a)(2)(v) are structured similarly for Day-Ahead Ninety-Minute Reserve Obligations and Day-Ahead Four-Hour Reserve Obligations, for the same reasons.

► **Reserve Constraint Penalty Factors.** The economic logic, interpretation, and purpose of Reserve Constraint Penalty Factors are discussed in detail in prior Section 6.4.3. As noted there, each reserve-related constraint in a co-optimized market requires a Reserve Constraint Penalty Factor.

New Sections III.2.6.2(b)(i)-(v) define the Reserve Constraint Penalty Factors applicable to the day-ahead co-optimized market's reserve-related constraints that can be satisfied with generation contingency reserve, replacement energy reserve, or both. In these provisions, the Reserve Constraint Penalty Factors are expressly associated to the corresponding (exogenous) Day-Ahead Ancillary Service Demand Quantity that defines how much should be procured to satisfy the applicable constraint.

Since the concept and purposes of Reserve Constraint Penalty Factors is discussed in detail above (*see* Section 6.4.3), here we limit our discussion to the rationale and reasoning for the specific numerical values specified in new Sections III.2.6.2(b)(i)-(v).

- Section III.2.6.2(b)(v) sets the Reserve Constraint Penalty Factor applicable to the Day-Ahead Total Four-Hour Reserve Demand Quantity at $100/MWh.

  To determine an appropriate Reserve Constraint Penalty Factor for this purpose, we used the model developed for the Impact Assessment to evaluate the maximum "re-dispatch" costs that would be incurred to enable that model of the co-optimized day ahead market to satisfy the full Day-Ahead Total Four-Hour Reserve Demand Quantity, for various scenarios evaluated in the Impact Assessment. The concept is that it would be undesirable to set a Reserve Constraint Penalty Factor too low, as that would cause frequent "artificial" shortages of replacement energy reserve. Such an outcome would undermine the reliability objectives and goals of procuring replacement energy reserve to meet the next-day operating plan's requirements.

Table 14 in the Impact Assessment summarizes the results of this analysis, for the three central cases evaluated. It shows that with a Reserve Constraint Penalty Factor set at $100/MWh (as was used to produce the results in that table), the system as modeled is able to satisfy the full Day-Ahead Total Four-Hour Reserve Demand Quantity between 98% and 100% of the time, depending upon the scenario. That is, shortages of this ancillary service capability would be highly infrequent. Other analyses (not reported in the Impact Assessment) using higher Reserve Constraint Penalty Factor test values (up to $500/MWh) did not show appreciable further reductions to the low frequencies of reserve shortages evident in Table 14.

Ultimately, as the ISO gains operating experience with this co-optimized day-ahead energy and ancillary service design, if we observe shortages of replacement energy reserve then the ISO can evaluate the causes and consider changes to this Reserve Constraint Penalty Factor value at a future date if circumstances warrant. In that way, with the benefit of experience and additional data, the value of the Reserve Constraint Penalty Factor can be more finely tuned, if necessary, to ensure the system does not experience "artificial" shortages of replacement energy reserve as a result of an Reserve Constraint Penalty Factor that is set too low.

- Section III.2.6.2(b)(iv) sets the Reserve Constraint Penalty Factor applicable to the Day-Ahead Total Ninety-Minute Reserve Demand Quantity at $250/MWh. This is based on the Commission-approved Reserve Constraint Penalty Factor currently applicable to the Total Reserve Requirement (including Replacement Reserve), which is enforced in the ISO's real-time dispatch.

  The Replacement Reserve was added to the real-time market in 2013.[151] It results in an additional quantity of Thirty Minute Operating Reserve being procured in the real-time market. This level of reserves was added, in part, to address similar concerns to those that will be addressed by the 90-minute replacement energy reserve product in the day-ahead market. Specifically, in its filing on the real-time Replacement Reserve, the ISO indicated that it "can maintain a quantity of replacement reserves . . . for the purposes of meeting the NERC requirement to *restore its total system TMR* [Ten-Minute Reserve] Requirement."[152] Importantly, the ISO performed simulations at the time that showed that $250/MWh is a reasonable indicator of the maximum redispatch cost for incremental reserve capability above the Total Thirty-Minute Requirement. In practice, violations of this Replacement Reserve component of the Total Thirty-Minute Requirement in the real-time market (indicating a redispatch cost to satisfy it in excess of $250/MWh) have been infrequent events.[153]

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[151] *See* Revisions to Market Rule 1 to Establish a Reserve Constraint Penalty Factor for Replacement Reserve Requirement, FERC Docket No. ER13-1736 (filed June 20, 2013), accepted by Letter Order dated August 15, 2013.

[152] *See id*., Joint Testimony of Robert G. Ethier and Christopher A. Parent, at p. 7 (emphasis added).

[153] Calculations based on the ISO's dispatch system data show that in 2018 and 2019, such violations occurred approximately 0.025 percent – that is, 2.5 hundredths of one percent – of the time.

On that basis, we have selected a $250/MWh Reserve Constraint Penalty Factor for the day-ahead Total Ninety-Minute Reserve Demand Quantity. As noted above, as the ISO gains operating experience with this co-optimized day-ahead energy and ancillary service market, the ISO can evaluate and consider changes to this Reserve Constraint Penalty Factor value at a future date if circumstances warrant. The infrequent violations of the Replacement Reserve component of the Total 30-Minute Requirement in the real-time market suggest that a $250/MWh for the 90-minute reserve capability (a product that should be in greater supply than 30-minute reserves in real-time) will not be systematically too low and will not result in frequent "artificial" shortages of replacement energy reserves.[154]

- Sections III.2.6.2(b)(i)-(iii) define the Reserve Constraint Penalty Factors applicable to the Day-Ahead Ancillary Service Demand Quantities that can be satisfied by only the three generation contingency reserve products. These are set, by reference to Section III.2.7A, to the corresponding Reserve Constraint Penalty Factors applicable to the analogous real-time Operating Reserve requirements for Ten-Minute Spinning Reserve, Ten-Minute Reserve, and the Minimum Total Reserve.

  The rationale for using the same Reserve Penalty Constraint Factors in the day-ahead and the real-time market for the analogous Demand Quantities (née requirements) is so that the day-ahead markets will send the same reserve shortage price signal if that shortage is anticipated by (that is, occurs in clearing) the day-ahead market. By doing so, the day-ahead market will signal the full value of actions that market participants may be able to take to help avoid, or reduce the magnitude of, a potential real-time reserve shortage that signals heightened reliability risks.

► Settlements of generation contingency reserve and replacement energy reserve obligations. Recall from Section 4 that market participants with cleared energy call option offers have two settlements associated with their energy call options. The first is a credit, at the market clearing price of the ancillary service product for which the energy option was cleared. The second is a charge, or the option close-out, which is equal to the real-time LMP less the strike price (but not less than zero). *See* examples (a) through (j) in Section 4.3.

The new Tariff provisions provide that each MWh of a seller's obligation for a generation contingency reserve or replacement energy reserve product will receive a payment at the corresponding products' day-ahead clearing price, and the corresponding option close-out charge.

- New Sections III.3.2.1(q)(1)(i)-(v) provide for the seller's credit, stipulating that each MWh of a generation contingency reserve or replacement energy reserve obligation will be paid the applicable day-ahead clearing price for the corresponding generation contingency reserve and replacement energy reserve product.

[154] For context, the Impact Assessment analysis of the co-optimized day-ahead market modeled a single replacement energy reserve product, more closely modeling the four-hour product than the ninety-minute product. As a result, this analysis was not able to directly inform the maximum redispatch cost for the 90-minute requirement.

- New Section III.3.2.1(q)(2)(ii) provides for the seller's option close-out charge. It stipulates that each MWh of a generation contingency reserve or replacement energy reserve obligation will be charged the energy option close-out amount. The option close-out amount is based on the Real-Time Hub Price and the energy option strike price, as explained in Section 4.3.2 (on option settlement location) and Section 4.5.2 (on strike prices).

► **Cost allocation for generation contingency reserve and replacement energy reserve.** The allocation of net costs and credits for generation contingency reserve and replacement energy reserve is contained in new Section III.3.2.1(q)(3). Like the energy imbalance reserve credits and charges to sellers, the generation contingency reserve and replacement energy reserve cost allocation has two components. One is the cost allocation (a charge) associated with the day-ahead generation contingency reserve and replacement energy reserve prices paid to sellers. This is provided in Section III.3.2.1(q)(3)(i). The second is the close-out offset (a credit) associated with the close-out of these sellers' day-ahead energy options. This is provided in Section III.3.2.1(q)(3)(ii).

These charges and credits are allocated to the system's real-time load, on the beneficiaries-pay principle. The reasoning is that the reserve requirements that enable the system to cover an unanticipated energy supply loss ensure the power system is prepared to reliably deliver energy to load *in real-time*. Real-time load is, therefore, ultimately the beneficiary of the costs incurred to satisfy the system's generation contingency reserve and replacement energy reserve requirements.

Section III.3.2.1(q)(3) contains an exclusion from these credit and charge allocations for the real-time load of storage resources (*i.e.,* Storage DARDs), for the reasons discussed in Section 6.6.2 above.

7.5 Example 4: Energy and One Ancillary Service Co-Optimization

To illustrate the pricing and clearing concepts of the prior sections, in this section and the next we provide a series of numerical examples. The purpose of these examples is to illustrate the pricing and clearing concepts with a co-optimized day-ahead energy and ancillary services market.

We start with a pair of examples in which we assume the market clears energy and a single generation contingency reserve product. For simplicity, we will assume in these first examples that energy demand clears at the forecast energy requirement, and there is no energy imbalance reserve (nor a need for it). We use these simplified settings in order to make transparent several important pricing properties.

In later examples in Section 7.6, we will build on these first two simple examples and examine situations with energy and multiple ancillary service products, and how their prices cascade. In Section 7.7, we then provide more involved examples involving energy imbalance reserve, the forecast energy requirement, and generation contingency reserve clearing simultaneously.

7.5.1 Example 4-A: Incorporating Opportunity Costs in the Day-Ahead LMP

This example considers the co-optimization of energy and generation contingency reserve when suppliers provide offers for each service. The main point of this first pair of examples is to show how the market clearing prices account for resources' inter-product opportunity costs in an economically appropriate way.

In particular, in the first example, we will see that energy option offers and the clearing price for generation contingency reserve can impact the day-ahead LMP. It does so in a way that differs from the outcomes that are possible in the existing real-time co-optimized energy and reserve market. The reason for this difference is that there are offers from suppliers in the day-ahead co-optimized market, whereas there are no offers to sell reserves in the real-time market.

Some useful notes on terminology: because there is a single generation contingency reserve product in this example and the next, we can interpret that term generically; that is, in this example, we do not specify whether it is for 10-minute spinning reserve, 10-minute non-spinning reserve, or 30-minute reserve. In addition, we will use the term 'reserve clearing price' (or RCP) to denote the market-clearing price for this day-ahead ancillary service.

Last, in both this example and the next, we will assume energy demand is inelastic, or non-price sensitive, and equal to the forecast energy demand. Treating energy demand as "fixed" will enable us to focus on the pricing impacts of resources' supply offers and their opportunity costs. In later examples, we will re-introduce priced demand bids that will further impact how the market clears.

► **Assumptions.** In this example, we revisit the same eight generators, Generator A through H, examined previously in Examples 3-A and 3-B in Section 6.3. For convenience, their energy supply offer prices and quantities (*i.e.,* resource capacities), and their energy option offer price and quantities, are reproduced in Table 7-7 below. Note that, as before, the generators are listed in ascending order of their energy offer price.

In this example, we have changed two things from the prior Example 3-B. First, energy demand is assumed be fixed at 720 MWh, as shown in row [10] of Table 7-7. Second, we assume there is an ancillary service demand quantity for generation contingency reserves of 190 MWh. *See* row [10] of Table 7-7. This is the only reserve product; that is, we do not model energy imbalance reserve or the forecast energy requirement here.

► **Market outcomes.** The market-clearing outcomes are summarized in the last two columns of Table 7-7. Generators A through D clear energy supply offers for a total of 720 MWh, equal to total energy demand. Generators D through F clear generation contingency reserve for a total of 190 MWh, equal to the ancillary service demand. The marginal offers for energy and for generation contingency reserve are those of Generator D and Generator F, respectively; for reference, these marginal offers, and the associated awards, are shaded in light orange in Table 7-7.

Table 7-7. Assumptions and Market Outcomes for Example 4-A							
		Supply Offer Assumptions				Day-Ahead Outcomes	
		Energy Supply Offers		Energy Option Offers		Market Awards	
		Price	Quantity	Price	Quantity	Energy	GCR
	Generator	($/MWh)	(MWh)	($/MWh)	(MWh)	(MWh)	(MWh)
[1]	A	$0	300			300	-
[2]	B	$10	150			150	-
[3]	C	$36	150	$2.59	100	150	-
[4]	D	$42	200	$2.59	100	120	80
[5]	E	$60	200	$5.05	90	-	90
[6]	F	$72	50	$5.54	50	-	20
[7]	G	$78	50	$5.82	50	-	-
[8]	H	$210	150			-	-
[9]	**Totals**		**1250**		**390**	**720**	**190**
						Day-Ahead Outcomes	
		Demand Assumptions (MWh)				Clearing Prices ($/MWh)	
		Energy Demand		GCR Demand		LMP	GCR
[10]	**Totals**		**720**		**190**	**$44.95**	**$5.54**

In this example, the cleared awards illustrate a property we'll call *stack separation.* That is, the resources with the lowest energy offer prices all clear for energy. These are Generators A through D. The resources that clear for reserve all have (equal or) higher energy offer prices. These are generators D through F. This mirrors the outcomes that are commonly observed in the real-time energy and reserve market, where the lowest-cost resources clear for energy, and higher cost resources remain in reserve.

As usual, it is helpful to interpret the market outcomes and clearing prices graphically. Figure 7-4 shows the supply and demand diagram for the assumptions and results in Table 7-7. The supply offers of Generators B, C, and D, which span the range where the market clears, are shown in the ascending stair-step supply 'curve' in blue. The energy call option offer prices for Generator D's remaining capacity (that is, its capability not cleared as energy), for Generator E, and for Generator F are shown in the green stair-step generation contingency reserve supply curve.

Note that, like the figures in Section 6 earlier, the supply curve of energy option offers is drawn starting from the quantity of energy cleared in the market, here 720 MWh. That is, in this figure, energy demand is represented by the vertical line at 720 MWh. The demand for generation contingency reserve, which is an additional 190 MWh, is drawn along the horizontal axis starting from the point where energy supply and demand clear and extending to (720 MWh + 190MWh) = 910 MWh.

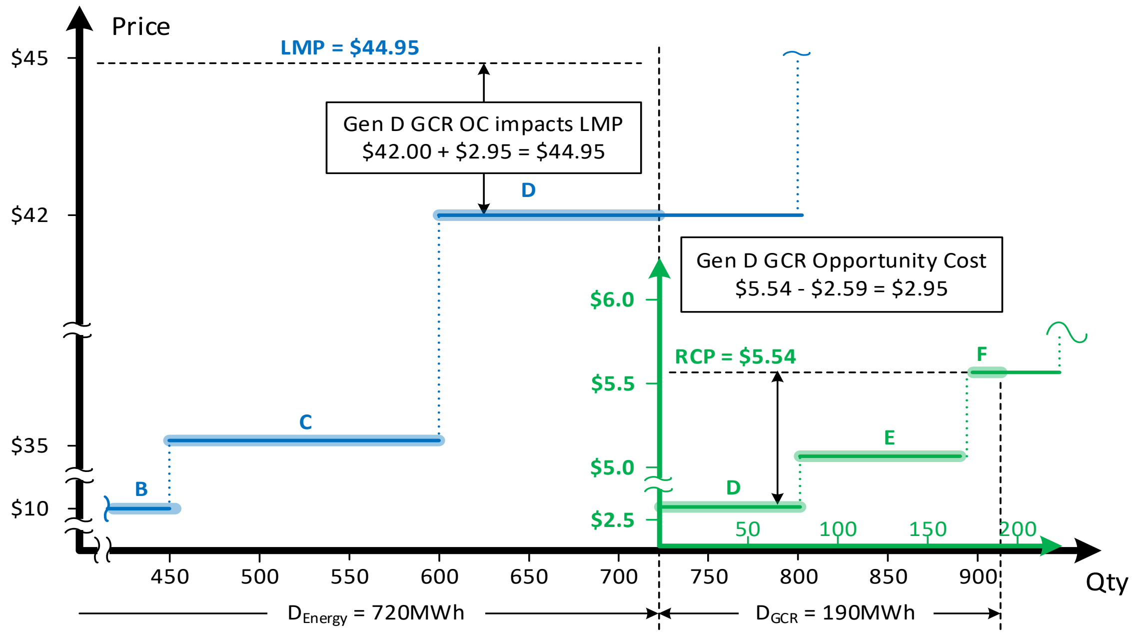

Figure 7-4. Market Clearing Outcomes for Example 4-A

► **Clearing prices.** The clearing price for generation contingency reserve is set by Generator F's energy option offer, at $5.54/MWh. Generator F has additional capability to supply another MWh of generation contingency reserve, and is the cheapest additional increment of supply available. Note that at this price, all resources with cleared energy call option offers are willing to accept that price or less; and all generators without cleared energy call option offers, and that did not earn greater profit clearing for energy, are not willing to accept that price.

What is the day-ahead LMP? Consider the marginal cost of serving another unit of energy. In Figure 7-7, Generator D is the marginal supplier of energy. However, it is also providing reserves with the full balance of its capability. Thus, to provide one more MWh of energy from Generator D, the amount of reserves from Generator D would have to be reduced by one MWh. Consequently, one additional MWh of reserves is required and would come from Generator F – the marginal resource for reserve. That additional cost of reserve must be accounted for in determining the marginal cost of serving energy demand.

Table 7-8 summarizes these calculations. Row [1] shows that the additional MWh of energy from marginal Generator D costs $42/MWh, its energy offer price. That reduces the system's purchase of generation contingency reserve from Generator D, a savings of $2.59/MWh, its energy option offer price. *See* row [4]. To continue to satisfy the generation contingency reserve demand of 190 MWh, we now must procure another MWh of generation contingency reserve from Generator F, the marginal resource for reserve. As shown in row [5], that cost is $5.54/MWh, its energy option offer price. Putting all the pieces together, the marginal cost to serve another unit of energy demand is $44.95/MWh, as shown in row [6]. Therefore, the day-ahead LMP is $44.95/MWh.

Table 7-8. Day-Ahead LMP Calculation for Example 4-A			
	Change in Total (Production) Costs for One More MWh of Energy Demand		
[1]	+ 1 MWh of energy from Generator D	$42.00	*Energy offer price of marginal Gen D*
[2]			*(results in one less MWh of GCR from Gen D)*
[3]	"Re-dispatch" GCR		
[4]	- 1 MWh of GCR from Generator D	($2.59)	*"Savings" from one less MWh of GCR from Gen D*
[5]	+ 1 MWh of GCR from Generator F	$5.54	*Option offer price to replace the GCR MWh from Gen F*
[6]		**$44.95**	*Marginal cost of energy (LMP)*

Note that, in Figure 7-4, this LMP is *higher* than the marginal energy supply offer price (that is, higher than Generator D's offer of $42/MWh). Thus, with co-optimization of energy and reserve, the LMP may not be set 'at' any resource's energy supply offer price. Rather, it may be set based on the offer prices of *two* marginal offers, one for energy supply and the other for energy options.

Does this energy price clear the market? Yes. At the day-ahead LMP of $44.95/MWh, all suppliers that cleared for energy are willing to accept that price or less; and no supplier that did not clear for energy would be willing to accept that price.

► **Prices and opportunity costs.** These prices have an important economic interpretation: they reflect marginal generator D's *opportunity costs* of supplying energy, rather than reserve.

To see this, notice that Generator D is more profitable providing reserve instead of energy. Its profit (per MWh cleared) providing reserve is the difference between the reserve clearing price (of $5.54/MWh) and Generator D's energy option offer price (of $2.59/MWh; see row [4] of Table 7-7). This difference, of $5.54/MWh – $2.59/MWh = $2.95/MWh, is Generator D's opportunity cost of being economically cleared for energy, instead of selling (additional) generation contingency reserve.

In order to make Generator D indifferent as to whether it supplies energy or reserve, this energy opportunity cost is incorporated *into* the LMP. That is, the day-ahead LMP is the sum of marginal energy supplier Generator D's energy offer price of $42/MWh and its energy opportunity cost of $2.95/MWh: $42/MWh + $2.95/MWh = $44.95/MWh.

Importantly, this opportunity cost perspective aligns perfectly with the method of calculating clearing prices based on the system's marginal costs to procure incremental demand. We will see this property frequently in later examples; it is a fundamental property of economically-appropriate price signals in an efficient, multi-product market.

► **Main points.** There are three points to note from this Example 4-A. First, the day-ahead LMP reflects the marginal cost of serving energy demand, consistent with economic principles. This marginal cost includes the *inter-product opportunity cost* of not supplying additional reserve that is incurred here by the marginal unit for energy.

That is a fundamental and critical element of sound market design in a multi-product market. To see why, consider what happens if the market clearing prices did not make a marginal supplier (of either product) indifferent between its cleared awards and an alternative set (any alternative set) of quantities. In that perverse situation, the marginal supplier would be incented to distort its offer prices to clear more of the product that provides it with a higher profit, and less of the product that does not. That distorted behavior would force the market to make up for the reduced supply of the latter by clearing more offers for it from other suppliers that have truly higher costs. And that distortion begets another in the same way, and so on. In summary, if prices do not properly compensate for sellers' opportunity costs in a multi-product market, it can undermine the efficiency and cost-effectiveness of the entire competitive market.

Second, in this example, the marginal energy supplier's opportunity cost is incorporated "inside" the day-ahead LMP. In later examples, when we add the forecast energy requirement and energy imbalance reserve, we will see that again the market must compensate the marginal energy supplier for its opportunity cost of not selling (additional) reserve. However, instead of incorporating that opportunity cost into the LMP, it will (often) be incorporated into the Forecast Energy Requirement Price instead. That is, in more general cases, the inter-product opportunity cost will be "outside" the LMP, and in the Forecast Energy Requirement Price instead. This will occur because the opportunity cost can arise for the physical supply resource that is marginal for satisfying the next-day's forecast energy requirement, not only the day-ahead market's bid-in energy demand. (Look for this in Examples 6-A and 6-B in Section 7.7 ahead).

Third, this property of the co-optimized day-ahead market specifically motivated the Tariff revisions in new Section III.2.6.1(a), which (as revised) provide that the detailed calculations of the LMP can account for the fact that the (marginal) cost of serving incremental energy demand can depend on ancillary services' offer prices as well.

7.5.2 Example 4-B: Incorporating Opportunity Costs in the Day-Ahead Reserve Price

In Example 4-A, we showed that the co-optimized market may produce an opportunity cost that is incorporated into the market's compensation to energy suppliers. However, that need not be the case. In this next Example 4-B, we show the reverse may also occur: the co-optimized market may produce an opportunity cost that is incorporated into the market's compensation to ancillary service suppliers.

For convenience, the revised energy supply offer prices and quantities (*i.e.,* resource capacities), and the energy option offer price and quantities, for all eight Generators A through H are reproduced in Table 7-9 below, with the change to Generator D as an 'energy-only' resource.

Note that, as before, the generators are listed in ascending order of their energy offer price.

Table 7-9. Assumptions and Market Outcomes for Example 4-B							
		Supply Offer Assumptions				Day-Ahead Outcomes	
		Energy Supply Offers		Energy Option Offers		Market Awards	
		Price	Quantity	Price	Quantity	Energy	GCR
	Generator	($/MWh)	(MWh)	($/MWh)	(MWh)	(MWh)	(MWh)
[1]	A	$0	300			300	-
[2]	B	$10	150			150	-
[3]	C	$36	150	$2.59	100	110	40
[4]	D	$42	200			160	-
[5]	E	$60	200	$5.05	100	-	100
[6]	F	$72	50	$5.57	50	-	50
[7]	G	$78	50	$9.07	50	-	-
[8]	H	$210	150			-	-
[9]	**Totals**		**1250**		**300**	**720**	**190**
						Day-Ahead Outcomes	
		Demand Assumptions (MWh)				Clearing Prices ($/MWh)	
		Energy Demand		GCR Demand		LMP	GCR
[10]	**Totals**		**720**		**190**	**$42.00**	**$8.59**

As before, demand is assumed be a fixed 720 MWh and there is an ancillary service demand quantity for generation contingency reserves of 190 MWh, both of which are shown in row [10] of Table 7-9. This is the only reserve product; that is, we do not model energy imbalance reserve or the forecast energy requirement here.

► **Market outcomes.** The market-clearing outcomes are summarized in the last two columns of Table 7-9. Generators A through D again clear energy supply offers for a total of 720 MWh, equal to total energy demand. Generators C, E, and F (but not D) clear generation contingency reserve for a total of 190 MWh, equal to the ancillary service demand. The marginal offers for energy and for generation contingency reserve are those of Generator D and Generator C, respectively; for reference, these marginal offers and associated awards are shaded in light orange in Table 7-9.

In this example, the cleared awards do not fully illustrate *stack separation.* Generator C has a lower energy supply offer price than the marginal energy Generator D, yet Generator C clears (some) generation contingency reserve as well. This occurs because the next higher energy call option price that is uncleared, from Generator G, is very expensive. Thus, the market clearing output pushes some energy award onto higher energy-cost Generator D, in order to procure generation contingency reserve from Generator C instead of expensive Generator G.

Figure 7-5 shows the supply and demand diagram for the assumptions and results in Table 7-9. The energy supply offers of Generators B, C, and D are the same here as in prior Figure 7-4. The energy call option offer curve is different than in the prior Figure 7-4, however, because Generator D is assumed to not offer one.

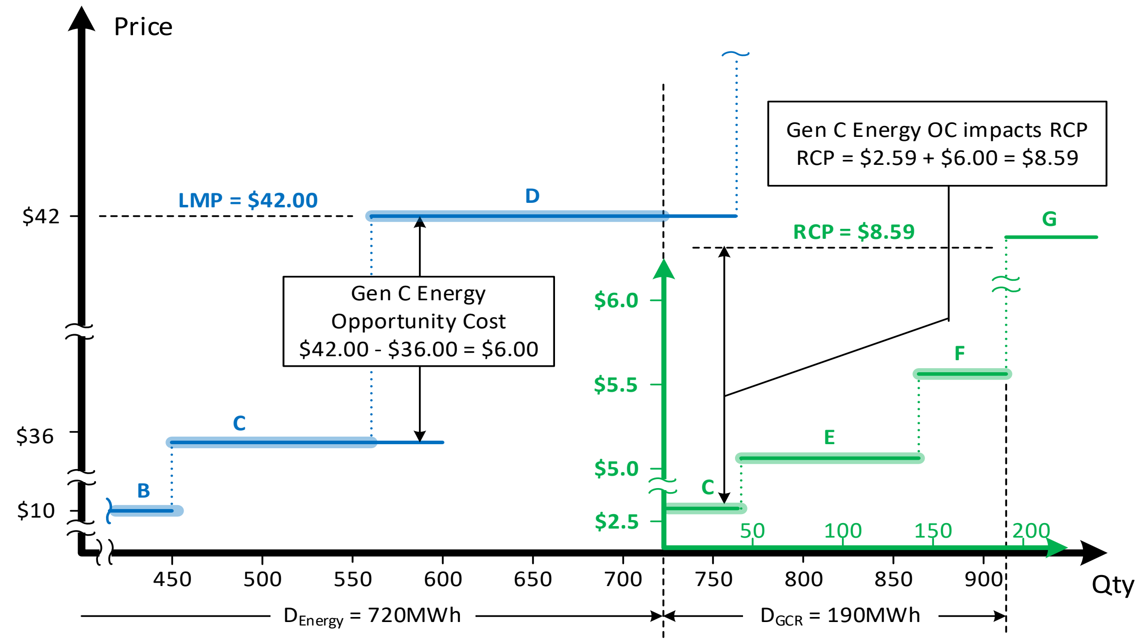

Figure 7-5. Market Clearing Outcomes for Example 4-B

► **Clearing prices.** Here, the day-ahead LMP is straightforward from Figure 7-5. Generator D is the highest-priced cleared energy supply offer, and does not sell all of its capability. It could therefore be used to serve the next increment of energy demand, at an incremental cost to the system set by Generator D's energy offer price of $42/MWh. The day-ahead LMP is therefore $42/MWh.

Does this price clear the market? At this price, all generators that clear for energy are willing to accept the price of $42/MWh or less; no generators that do not sell energy would be willing to do so at this price. *But,* there is one more thing to check: Generator C. Would it be willing to sell more energy at $42/MWh, given the profit it earns on its generation contingency reserve? To answer this question, we need to establish the clearing price for reserve. Two different methods arrive at exactly the same conclusion.

The marginal cost ('redispatch') method. Consider the marginal cost of procuring another unit of generation contingency reserve. Table 7-10 summarizes these calculations. Row [1] shows the additional MWh of generation contingency reserve from the marginal-for-reserve Generator C costs $2.59/MWh, its energy option offer price. That reduces the system's purchase of energy from Generator C, a savings of $36/MWh, its energy supply offer price. *See* row [4]. To continue to satisfy the energy demand of 720 MWh, however, the system must now procure another MWh of energy from marginal-for-energy Generator D. As shown in row [5], that cost is $42/MWh, its energy supply offer price. Putting all the pieces together, the marginal cost to procure another unit of generation contingency reserve $8.59/MWh, as shown in row [6]. Therefore, the reserve clearing price (RCP) is $8.59/MWh.

Now, back to the question earlier: does the $42/MWh LMP, *and* the $8.59/MWh RCP, clear this market? Now we can say yes. At this price, as before, all generators that clear for energy are willing to accept the price of $42/MWh or less; no generators that do not sell energy would be willing to do so at this price. And Generator C earns $6/MWh on the generation contingency reserve it sells: an $8.59/MWh RCP less Generator C's $2.59 energy call option offer price yields $6/MWh. That is no better than the $6/MWh it earns selling energy: A $42/MWh LMP less Generator C's $36/MWh energy supply offer price yields $6/MWh. The market clears.

Table 7-10. GCR Clearing Price Calculation for Example 4-B

	Change in Total (Production) Costs for One More MWh of GCR Demand		
[1]	+ 1 MWh of GCR from Generator C	$2.59	*Option offer price of GCR-marginal Gen C*
[2]			*(results in one less MWh of energy from Gen C)*
[3]	"Re-dispatch" Energy		
[4]	- 1 MWh of energy from Generator C	($36.00)	*"Savings" from one less MWh of energy from Gen C*
[5]	+ 1 MWh of energy from Generator D	$42.00	*Replacment cost of 1 MWh energy from marginal Gen D*
[6]		**$8.59**	*Marginal cost of GCR (GCR Clearing Price)*

The opportunity cost method. The economic perspective on the reserve clearing price is again in terms of opportunity cost. To see this, note again that Generator C's profit selling energy is the $42/MWh LMP less its energy supply offer price of $36/MWh, or $6/MWh. This is its opportunity cost of being cleared for reserve (per MWh of reserve), instead of being cleared for (additional) energy.

In order to make Generator C indifferent as to whether it supplies energy or reserve, this energy opportunity cost is incorporated *into* the reserve clearing price. Thus, the RCP is the sum of marginal generation contingency reserve seller Generator C's energy call option offer price of $2.59/MWh and its energy opportunity cost of $6/MWh: $2.59/MWh + $6/MWh = $8.59/MWh.

As before, this opportunity cost perspective aligns perfectly with the method of calculating clearing prices based on the system's marginal costs to procure incremental reserve.

► **Main points.** There are five points to note from this Example 4-B. First, the day-ahead LMP reflects the marginal cost of serving energy demand, and the RCP reflects the marginal cost of generation contingency reserve, consistent with sound economic principles. The marginal cost of generation contingency reserve includes the *inter-product opportunity cost* of not supplying additional energy that is incurred here by the marginal unit for reserve.

Second, this situation is analogous to the real-time co-optimized energy and reserve market. In that market, the real-time reserve clearing price is set by the marginal reserve resource's opportunity cost of not selling additional energy.

Third, consider why the opportunity cost is incorporated in the reserve clearing price in this Example 4-A, whereas it was incorporated in the energy clearing price (that is, the LMP) in prior example 4-A. First, a bit of terminology: we say that a resource is *capacity limited* if the sum of all of its awards (that is, energy MWh cleared and total energy option offer MWh cleared) is equal to the resource's total capacity. In Example 4-A, the marginal unit for *energy* is capacity limited; in that case, its opportunity cost is incorporated into the *energy* price. In this Example 4-B, the marginal unit for *reserves* is capacity limited; in this case, its opportunity cost is incorporated into the *reserve* price. This is true generally. And both situations are possible in practice, depending upon the precise combination of energy and option offers hour to hour.

Fourth, observe that in both Examples 4-A and 4-B, the clearing prices reflect the offers of the marginal units, but are not necessarily *equal to* the offers of the marginal units. That is because a co-optimized market will endogenously determine the correct intertemporal opportunity costs*,* and incorporate those into the market clearing prices.

Fifth, this example also illustrates that energy option offer prices *may* impact energy prices (as in Example 4-A), but do not necessarily impact energy prices (as in this Example 4-B). Put differently, reserve clearing prices do not 'cascade' into the energy price. This is in contrast to pricing for the various generation contingency reserve and replacement energy reserve products, the prices of which do cascade. We show this in our next two examples.

7.6 Example 5: Energy and Multiple Ancillary Service Co-Optimization

In this section, we now consider a pair of examples with co-optimization of energy and multiple generation contingency reserve and replacement energy reserve products. These examples will illustrate the price cascading logic of generation contingency reserve and replacement energy reserve, and how it sends the economically-correct price signals to the market.

In the next example 5-A in Section 7.6.1, we extend the assumptions in prior Example 4 to consider two generation contingency reserve products: 10-minute reserve, and 30-minute reserve. We will explain the price cascading logic using this two-reserve product example. Then, in Example 5-B in Section 7.6.2, we consider a situation with four products that includes both generation contingency reserve and replacement energy reserve, and examine the co-optimized market's price cascading logic in greater detail.

7.6.1 Example 5-A: Price Cascading with Two Generation Contingency Reserve Products and Co-optimized Energy

In Example 4-B, we showed that the co-optimized market may produce an opportunity cost that is incorporated into the market's compensation to reserve suppliers. In this example, that will continue to be the case. Our central point in this example is to show that the price cascading logic (and all the mathematics that goes with it) is, in effect, a method to ensure that the market properly incorporates seller's opportunity costs into the (correct) reserve prices.

This fact often lies just past intuition when contemplating a market with multiple ancillary services, as under the co-optimized day-ahead market upon implementation of these Energy Security Improvements. Thus, in this Example 5-A and the next Example 5-B, we show this that incorporating opportunity costs into reserve clearing prices is equivalent to the price cascading structure calculation discussed above, in Section 7.2.3.

► **Assumptions.** In this example, we make only one change from prior Example 4-B. We now assume that higher-cost Generator G submits a lower energy option offer price than in Example 4-B. That will enable it to receive a (partial) award, and better illustrate price cascading outcomes.

With multiple generation contingency reserve products, we now need to consider resources' ramp rates explicitly. Consistent with the co-optimized day-ahead market design and new market rules, we assume that:

- Each generator voluntarily chooses its energy call option offer price, and its energy call option offer MWh.
- The market-clearing software will calculate each generators' ramping capability (within 10-minutes, and within 30-minutes), based on the generators' submitted operating characteristics (*e.g.*, their submitted ramp rates, in MW per minute).
- Market awards for any generation contingency reserve or replacement energy reserve product will be limited by the lesser of: (a) the generator's offered energy call option offer MWh, and (b) the generator's total ramping capability corresponding to each product.

For example, if a generator offers 20 MWh of energy call option offers but can only ramp up at a rate of 1 MW per minute, its maximum possible award for GCR 10-minute reserve would be 10 MWh (10 minutes × 1 MW/minute × 1 hour award duration = 10 MWh).

Alternatively, if that generator only offered 5 MWh of energy call option offers, and had the same ramp rate, its maximum possible award for GCR 10-minute reserves would be only its 5 MWh offer. That is, no resource will receive a reserve award for a quantity that is did not offer to sell.

The same logic applies for all generation contingency reserve and replacement energy reserve product awards.

For convenience, the revised energy supply offer prices and quantities (*i.e.,* resource capacities), and the energy option offer price and quantities, for all eight Generators A through H are reproduced in Table 7-11 below, with the change to Generator G's energy call option offer price (now a lower value than assumed value in Example 4-B previously).

Last, in addition to the energy demand of 720 MWh as in the prior examples, we will assume a total-10 minute reserve demand quantity of 250 MWh, and a total 30-minute reserve demand quantity of 320 MWh. *See* row [10] in Figure 7-11. Note that, as discussed in Sections 7.2.2 and 7.2.3, these reserve demand quantities are *cumulative,* so awards of both GCR 10-minute reserve and GCR 30-minute reserve contribute to the total 30-minute reserve demand quantity.

Table 7-11. Assumptions and Market Outcomes for Example 5-A										
		Supply Offer Assumptions				Reserve Capability		Day-Ahead Outcomes		
		Energy Supply Offers		Energy Option Offers		10-min	30-min	Market Awards		
		Price	Quantity	Price	Quantity	Quantity	Quantity	Energy	GCR10	GCR30
	Generator	($/MWh)	(MWh)	($/MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)
[1]	A	$0	300					300	-	-
[2]	B	$10	150					150	-	-
[3]	C	$36	150	$2.59	150	100	150	100	50	-
[4]	D	$42	200					170	-	-
[5]	E	$60	200	$5.05	200	100	200	-	100	70
[6]	F	$72	50	$5.57	50	50	50	-	50	-
[7]	G	$78	50	$5.81	50	50	50	-	50	-
[8]	H	$210	150					-	-	-
[9]	**Totals**		**1250**		**450**	**300**	**450**	**720**	**250**	**70**
								Day-Ahead Outcomes		
		Demand Assumptions (MWh)						Clearing Prices ($/MWh)		
		Energy Demand		Total 10-min Demand		Total 30-min Demand		LMP	GCR10	GCR30
[10]	**Totals**	**720**		**250**		**320**		**$42.00**	**$8.59**	**$5.05**

In Table 7-11, the columns labeled Reserve Capability reflect the ramp rates for each generator that submitted an energy call option offer.[155] These are limiting only for Generators C and E: both can ramp up to their full energy option offer MWh in 30 minutes, but not in 10 minutes.

► **Market outcomes.** The market-clearing outcomes are summarized in the last three columns of Table 7-11. Generators A through D again clear energy supply offers for a total of 720 MWh, equal to total energy demand. Generators C, E, F, and G (but not D) clear GCR 10-minute reserve in a total amount of 250 MWh, equal to the total 10-minute reserve demand. Generator E clears GCR 30-minute reserve of 70 MWh. The sum of all GCR 10-minute reserve and GCR 30-minute reserve cleared therefore satisfies the total 30-minute demand quantity (250 MWh clearing as GCR 10-minute reserve and 70 MWh clearing as GCR 30-minte reserve adding to just satisfy the 320 MWh total 30-minute reserve demand quantity).

As is our convention, the marginal offers for energy and for each reserve product are shaded in light orange in Table 7-11. Generator D is again the marginal offer for energy; higher-priced Generator E is the marginal offer for GCR 30-minute reserve; but *lower*-priced Generator C is the marginal offer cleared for GCR 10-minute reserve.

[155] In practice, the ISO's market clearing system uses both on-line ramping rates and off-line startup times in determining these reserve capabilities, and accounts for both in making both commitment and reserve capability evaluations. We will not consider that level of detail here, in order to focus on the economic aspects of market prices.

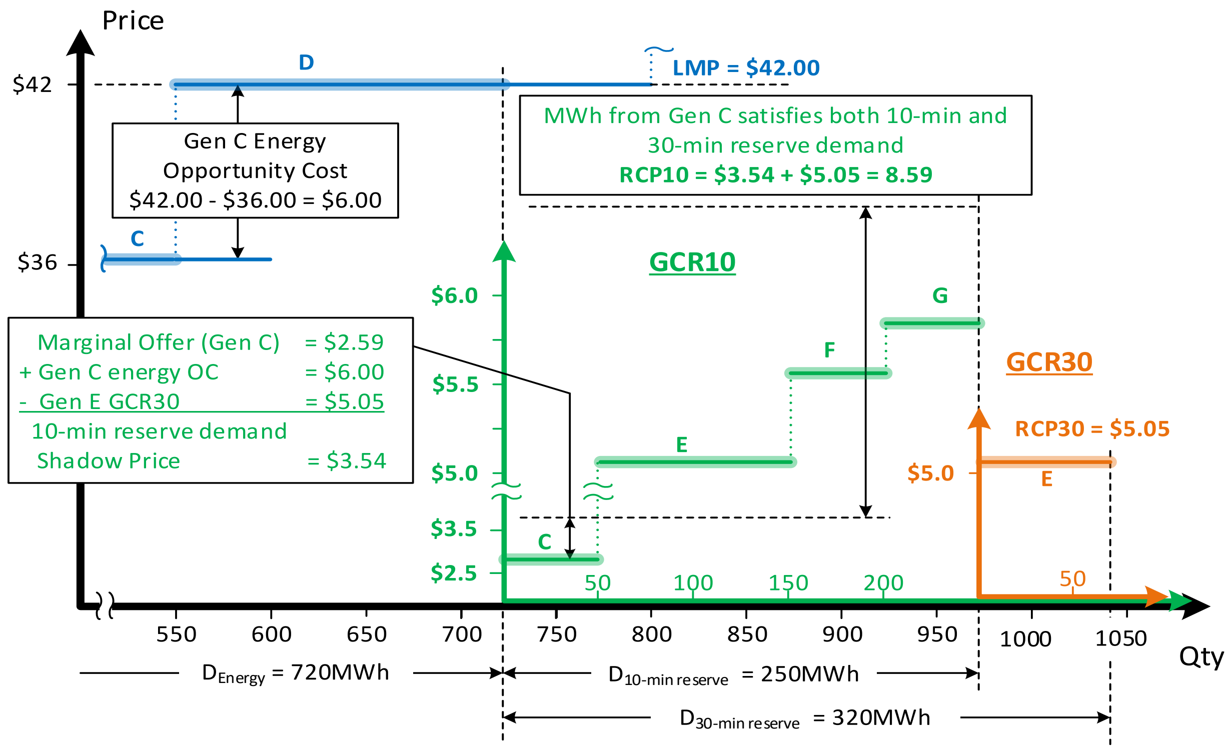

Figure 7-6. Market Clearing Outcomes for Example 5-A

That last observation suggests that Generator C may have an opportunity cost associated with its award. And indeed that is the case. To see how that plays out, Figure 7-6 shows the supply and demand diagram for the assumptions and results in Table 7-11.

Using the results in the last three columns of Table 7-11, Figure 7-6 shows the supply stack of energy supply offers and energy option offers that are cleared for each product. The energy supply stack, here showing the energy supply offers only for Generators C and D, is the same here as in prior Figure 7-4. The green stair-step supply curve in the middle represents the cleared GCR 10-minute reserve awards, in merit (*i.e.*, ascending offer price) order. The orange axes at the far right show the lone GCR 30-minute reserve award cleared, for Generator E.

► **Clearing prices and opportunity costs.** First, consider energy. The highest-priced cleared energy supply offer is from Generator D, and it has excess capacity to spare at its cleared energy quantity. So it would be used to satisfy an increment of energy demand, at a marginal cost to the system equal to its energy supply offer price of $42/MWh. Therefore, the day-ahead LMP is $42/MWh.

Now, at the opposite end of Figure 7-6, consider GCR 30-minute reserve. Generator E did not receive an award for all of its GCR 30-minute reserve; it has additional capability to spare. So it would be used to satisfy an increment of total 30-minute reserve demand, at a marginal cost to the system equal to is energy call option offer price of $5.05/MWh. Therefore, the market clearing price for GCR 30-minute reserve is $5.05/MWh.

Now, let's consider the price for GCR 10-minute reserve, in green in Figure 7-6. As noted in Table 7-11, lower-priced Generator C clears 100 MWh of energy, and 50 MWh of GCR 10-minute reserve. As a result, Generator C is capacity limited for energy and reserve. For energy, it is earning an LMP of $42/MWh and has an energy supply offer price of only $36/MWh, so it earns $42/MWh – $36/MWh = $6/MWh in profit on its energy. For each MWh of GCR 10-minute reserve it clears, then, it faces on opportunity cost of $6/MWh for not selling (additional) energy. Its marginal cost of supplying GCR 10-minute reserve is, as always in a multi-product market, the sum of its offer price and its opportunity cost of not selling something else. In this case, that comes to ($2.59/MWh energy option offer price + $6/MWh energy opportunity cost) = $8.59/MWh. Therefore, the market clearing price for GCR 10-minute reserve must be (at least) $8.59/MWh.

At these prices – the $42/MWh LMP, $8.59/MWh clearing price for GCR 10-minute reserve, and $5.05/MWh clearing price for GCR 30-minute reserve – each seller with an award of any product type is willing to accept that price or less, and no seller that is not awarded that product type would be willing to accept it a lower price. Therefore, the market clears.

► **Clearing prices: the price cascading method.** Now, this last step – checking that at all those prices, all of those sellers, with all of those offers, would find those prices to be their 'best deal' – is a doozy. It is work to check here, with eight generators and three products. It would be impractical to do so directly in a real co-optimized day-ahead market with a thousand resource offers and six ancillary service products.

Fortunately, there is a different way. The clearing prices can be calculated directly from the marginal cost logic, or the *shadow prices*, discussed previously in Section 7.2.3, and then 'cascaded' to set the clearing prices.

Table 7-12 steps through the calculations for the GCR 10-minute reserve clearing price. First, consider a 1 MWh increase in the 10-minute reserve demand quantity. That has a cost of $2.59/MWh, its energy call option offer price, as shown in row [2]. Procuring that from the marginal seller Generator C reduces its supply of energy by 1 MWh, because Generator C is capacity limited (the sum of its energy and GCR 10-minute reserve awards equals its total capacity). That would require another MWh of energy from the marginal energy supplier, Generator D, at a cost of $42/MWh; *see* row [6].

But, there is a another cost savings term to account for, because of the *product substitution* effect. Procuring another MWh of GCR 10-minute reserve contributes not only to the 10-minute reserve demand quantity, but also to the GCR 30-minute reserve demand quantity. That means the system can procure one less MWh of GCR 30-minute reserve, from Generator E. And that has a cost savings of $5.05/MWh, equal to Generator E's energy option offer price. *See* Row [9].

Table 7-12. GCR 10-Minute Reserve Clearing Price Calculation for Example 5-A			
[1]	**Change in Total (Production) Costs for One More MWh of 10-min Reserve Demand**		
[2]	+ 1 MWh of GCR10 from Generator C	$2.59	*Option offer price of GCR10-marginal Gen C*
[3]			*(results in one less MWh of energy from Gen C)*
[4]	"Re-dispatch" Energy		
[5]	- 1 MWh of energy from Generator C	($36.00)	*"Savings" from one less MWh of energy from Gen C*
[6]	+ 1 MWh of energy from Generator D	$42.00	*Replacment cost of 1 MWh energy from marginal Gen D*
[7]			
[8]	Substitution Effect of GCR10 for GCR30		
[9]	- 1 MWh of GCR30 from Generator E	($5.05)	*"Savings" from one less MWh of GCR30 from Gen E*
[10]		$3.54	*Shadow price of 10-min Reserve Demand*
[11]	Participation Payment Principle		
[12]	GCR10 contributes to 30-min Reserve Demand	$5.05	*Shadow price of 30-min Reserve Demand*
[13]		$8.59	*GCR 10-minute reserve clearing price*

Adding these all together yields the sum in row [10] of $3.54/MWh. That is the direct marginal cost of the *requirement*, that is, to satisfy another MWh increase in the 10-minute reserve demand quantity.

But that is not the market clearing price for the *product.* To get the correct product price, we have to apply the participation payment principle; *see* Section 7.2.3. Specifically, each MWh of GCR 10-minute reserve also contributes to the total 30-minute reserve demand quantity, which has a marginal cost of $5.05/MWh (set by Generator E's energy option offer price). Since each MWh of GCR 10-minute reserve contributes to both demand quantities, it must be paid the (shadow) price of each. The clearing price paid for the GCR 10-minute reserve *product* is therefore the sum of the two marginal costs: $3.54/MWh + $5.05/MWh = $8.59/MWh. *See* row [13].

► **Main points.** With multiple products that are one-way substitutes, as are generation contingency reserve and replacement energy reserve, there are two economically equivalent ways to interpret the market clearing prices. One is in terms of offer prices and opportunity costs. The other is the price cascading logic, which is how the clearing prices are calculated from incremental costs (or, more precisely, constraint shadow prices) in the actual market pricing software with thousands of offers.

The price cascading logic illustrated in Table 7-12 also reflects how the new Tariff provisions are written for the clearing prices for generation contingency reserve and replacement energy reserve in new Tariff Sections III.2.6.2(a)(ii)-(v). In particular, each price in Sections III.2.6.2(a)(ii)-(v) is determined by the marginal (that is, the incremental) cost of an incremental increase in the corresponding Day-Ahead Ancillary Service Demand Quantity, plus the clearing price of the specific Day-Ahead Ancillary Service Demand Quantity that is one step "lower" in the product substitution hierarchy. In this way, the pricing rules expressly and transparently incorporate the price cascading logic described above.

7.6.2 Example 5-B: Generation Contingency Reserve and Replacement Energy Reserve

The previous examples illustrated two key properties of the co-optimized day-ahead energy and ancillary services market. First, for generation contingency reserve and replacement energy reserve, calculating prices using the price cascading logic sets prices that properly compensate sellers for their inter-product opportunity costs. Second, incorporating those opportunity costs into the (correct) product prices clears the market: all awarded sellers are willing to accept that price or less, and all non-awarded sellers (of that product) would not be willing to accept that price.

The same price cascading and opportunity cost logic that applied to generation contingency reserve in the prior example also applies to replacement energy reserve, which shares the same product substitution and price cascading design. For completeness, we include here an example involving both generation contingency reserve and replacement energy reserve clearing and pricing.

In particular, this example will illustrate that generation contingency reserve and replacement energy reserve clearing prices cascade from slowest-ramping products to fastest-ramping products. The clearing prices resulting from this price cascading provides appropriate compensation, reflecting cleared option offer prices as well as opportunity costs.

► **Assumptions.** In this example, we have changed the offer prices for energy and energy options from the prior examples, to better illustrate multi-product price cascading. Table 7-13 summarizes the revised example assumptions. The last four columns reflect each generator's assumed ramping capability, from an on-line state and from an off-line state, within the time limits shown. As noted previously, these capabilities are based on generators' physical offer parameter data (*e.g.,* ramp rates, startup times, and such). The energy demand and total ancillary service demands are shown in row [9] of Table 7-13.

In this example, all generators that offer energy options offer their full capability as both energy and as energy call option offers. This is, in general, efficient; it lets the co-optimization logic find the most cost-effective (and profitable) assignment of awards to their resource's capabilities.

Nonetheless, we will assume that two generators choose not to offer energy call options (A and E). Two resources offer offline capability for clearing energy call options, higher-cost Generators F and G. In particular, Generator F can be online at its maximum output within 10 min; Generator G is slower, and can start up and reach 5 MW in 90 min and its maximum output within 4 hours.

► **Market outcomes.** The co-optimized market awards are shown in Table 7-14. Energy and reserve awards clear in the most efficient fashion, while respecting individual resource startup and ramping constraints. The reserve awards cascade to satisfy less restrictive requirements. For instance, the sum of all reserve awards shown in row [8] of Table 7-14 are equal to their respective total reserve demand quantities in row [8] of Table 7-13; or, stated more simply, the market clears sufficient reserve supply to (just) satisfy each reserve demand quantity in row [8] of Table 7-13.

Table 7-13. Assumptions for Example 5-B

		Supply Offer Assumptions				Reserve Capability (Online / *Offline*)			
		Energy Supply Offers		Energy Option Offers		10-min	30-min	90-min	240-min
		Price	Quantity	Price	Quantity	Quantity	Quantity	Quantity	Quantity
	Generator	($/MWh)	(MWh)	($/MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)
[1]	A	$10	450						
[2]	B	$36	150	$2.59	150	30 / -	90 / -	150 / -	150 / -
[3]	C	$42	200	$2.59	200	20 / -	60 / -	180 / -	200 / -
[4]	D	$60	160	$5.04	160	10 / -	30 / -	90 / -	160 / -
[5]	E	$72	40						
[6]	F	$78	100	$5.82	100	100 / *100*	100 / *100*	100 / *100*	100 / *100*
[7]	G	$210	20	$8.00	20	10 / -	20 / -	20 / *5*	20 / *20*
[8]	**Totals**		**1120**		**630**	**170 / *100***	**300 / *100***	**540 / *105***	**630 / *120***
						Reserve Demand (MWh)			
		Energy Demand (MWh)				**10-min**	**30-min**	**90-min**	**240-min**
[9]		**820**				**150**	**240**	**260**	**270**

Table 7-14 - Award Quantities for Example 5-B

		Award Quantities				
		Energy	GCR10	GCR30	RER90	RER240
	Generator	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)
[1]	A	450				
[2]	B	100	30	20		
[3]	C	140	20	40		
[4]	D	115	0	30	15	
[5]	E	15				
[6]	F		100			
[7]	G				5	10
[8]	**Totals**	**820**	**150**	**240**	**260**	**270**

Table 7-15. Pricing Outcomes for Example 5-B

	Demand	Shadow Price	Reserve	Clearing Price
	Quantity	($/MWh)	**Product**	($/MWh)
[1]	**Energy**	$72	Energy	$72
[2]	Total 10	$0	GCR10	$38.59
[3]	Total 30	$21.55	GCR30	$38.59
[4]	Total 90	$9.04	RER90	$17.04
[5]	Total 240	$8	RER240	$8

► **Price cascading and clearing prices.** Table 7-15 shows the pricing outcomes. The shadow prices reflect the cost, at the margin, that would be incurred to meet an additional MWh of each demand quantity. The reserve product clearing prices, in the far-right column of Table 7-15, reflect the cascading of shadow prices. This satisfies the participation payment principle, and closely aligns with the structure of the clearing price definitions for generation contingency reserve and replacement energy reserve in new Tariff Sections III.2.6.2(a)(ii)-(v).

In Table 7-15, note that the reserve product clearing prices exceed (most) option offer prices, because the clearing prices incorporate the marginal resources' opportunity costs. As an example, consider the compensation of offline Generator G, which clears 5 MWh of RER 90-minute reserve and 10 MWh of RER 240-minute reserve. Its RER 90-minute reserve award helps to satisfy both the total 90- and total 240-minute demand quantities. From the participation payment principle, this award must be paid the shadow prices of *both* demands (constraints). Hence, the RER 90-minute reserve clearing price is $17.04/MWh (the sum of the shadow prices in row [4] and row [5] of Table 7-15 is $8/MWh + $9.04/MWh = $17.04/MWh). Generator G's total RER 90 award compensation is therefore 5 MWh x $17.04/MWh = $85.20.

Generator G's RER 240-minute reserve award helps to satisfy only the total 240-minute demand quantity. This award must be paid only the total 240-minute demand quantity shadow price. Hence, the RER 240-minute reserve clearing price is $8/MWh. Its RER 240-minute reserve award compensation is 10 MWh x $8/MWh = $80.

Finally, observe that the clearing price for GCR 10-minute reserve in row [2] of Table 7-15 and the clearing price for GCR 30-minute reserve in row [3] are the same, at $38.59/MWh. If the total 10-minute reserve demand quantity increased by one MWh, then marginal Resource D would clear 1 MWh of GCR 10-minute reserve (at a cost equal to its offer price, of $5.04/MWh), and one less MWh of GCR 30-minute reserve (at a savings equal to its offer price, of $5.04/MWh). That is, the "redispatch" occurs within the same resource. No incremental cost is incurred, so the shadow price is $0/MWh. This is why GCR 10-minute reserve and GCR 30-minute reserve have the same clearing price.

► **Prices reflect opportunity costs.** Consider the GCR 30-minute reserve clearing price of $38.59/MWh shown in row [3] of Table 7-15. Resource B is marginal for satisfying the total 30-minute demand quantity. This clearing price reflects both its energy call option offer of $2.59/MWh, and its energy opportunity cost of $36/MWh ($72/MWh LMP – $36/MWh energy offer = $36/MWh opportunity cost of not selling additional energy). The GCR 30-minute reserve clearing price is therefore $36/MWh + $2.59/MWh = $38.59/MWh.

Now consider the RER 90-minute reserve clearing price of $17.04/MWh shown in row [4] of Table 7-15. Resource D is marginal for satisfying the total 90-minute demand quantity. The clearing price reflects both its energy call option offer of $5.04/MWh, and its energy opportunity cost of $12/MWh ($72 LMP/MWh – $60/MWh energy offer = $12/MWh). The RER 90-minute reserve clearing price is therefore $12/MWh + $5.04/MWh = $17.04/MWh.

► **Summary.** This extended example further illustrates that how generation contingency reserve and replacement energy reserve clearing prices cascade up, so that sellers of faster-ramping products (higher in the product substitution hierarchy) always receive a price equal to or greater than sellers of slower-ramping products (lower in the product substitution hierarchy). The clearing prices reflect cleared option offer prices as well as opportunity costs, the participation payment principle, and basic foundation of marginal cost-based pricing.

7.7 Example 6: Energy Imbalance Reserve and Generation Contingency Reserve

We now return to the energy imbalance reserve and forecast energy requirement previously discussed in Section 6, and consider a pair of examples with both energy imbalance reserve and generation contingency reserve.

As motivation, consider again the results from Example 4-A. There, we found that with the single generation contingency reserve product, the day-ahead LMP was $44.95/MWh – higher than the marginal energy generator's offer price of $42/MWh. That $2.95/MWh difference appropriately reflected the generator's opportunity cost.

But consider that from a broader economic perspective. There is no generation contingency reserve in the real-time market – at least, not as an energy call option. If fact, there are no real-time reserve offer prices at all. Thus, the intertemporal opportunity cost for this marginal generator that was incorporated into the day-ahead LMP would, in all likelihood, not exist in the real-time market

In particular, suppose there is a zero real-time reserve price. Then, in the context of the results in earlier Example 4-A, market participants on the buy side of the market would see a higher price day-ahead – at the day-ahead LMP of $44.95/MWh – and a lower price in real-time, where there is no opportunity cost due to energy call options. Let's say that no system conditions change from day-ahead to real-time, so the real-time LMP is set by that same generator's offer price – which was $42/MWh.

That price spread would seem to have an undesirable effect: it would create an incentive for the demand side of the market to *not* buy energy day-ahead at $44.95/MWh, but instead to 'wait' and buy energy in real-time when it is cheaper, at $42/MWh. And it would be incented to continue to do so, until it bought sufficiently little day-ahead to 'back down' the day-ahead supply curve to where it equals the expected real-time price of $42/MWh. And that, in turn, would tend to create a problematic incentive for a *larger* energy gap between the day-ahead market outcome and the forecast energy requirement.

Of course, that seeming implication of Example 4-A isn't the full story. It isn't the full story because generation contingency reserve and replacement energy reserve are not being implemented in isolation. They and the forecast energy requirement within the co-optimized day-ahead market are a tightly coupled package, and have important interactions. In particular, the forecast energy requirement, its pricing, and the energy imbalance reserve effectively counter the potential incentive for demand to shift out of the day-ahead market, when suppliers' inter-product opportunity costs are now directly priced into the day-ahead energy price.

This plays out, in contrast to earlier Example 4-A, because the opportunity cost that went "into" the day-ahead energy price in that example will, in market equilibrium, instead tend to be incorporated into the Forecast Energy Requirement Price. And by so doing, the best that demand can do is *not* to avoid procuring energy day-ahead, but to procure as close to the forecast energy requirement as possible. In sum, arbitrage (by the demand side of the market) that seeks to avoid paying suppliers' energy opportunity costs (due to the generation contingency reserve and replacement energy reserve services) by withholding demand from the day-ahead market does not, in the end avoid paying suppliers' energy opportunity costs under these Energy Security Improvements.

We explore this important mechanism with the next pair of examples. To facilitate the analysis, we will use the same supply-side assumptions as in Example 4-A, with a single generation contingency reserve product. However, we will now enrich the demand side of the model, introducing demand side bidding, energy imbalance reserve, and the forecast energy requirement.

7.7.1 Example 6-A: The Forecast Energy Requirement Covers Energy Opportunity Costs

In this example, we revisit the same eight generators, Generator A through H, examined previously in Example 4-A in Section 7.5.1. Now, let's see what happens under the same supply conditions, with the forecast energy requirement and energy imbalance reserve added to the example.

Before proceeding, recall the key results from earlier example 4-A (*see* Section 7.5.1):

- Generator D's energy supply offer at $42/MWh was the marginal offer for energy.
- Generator D also sold generation contingency reserve, at a profit of $2.95/MWh.
- It therefore incurred an energy opportunity cost of $2.95/MWh.
- Proper marginal cost pricing, in that example, incorporated that $2.95/MWh opportunity cost for the marginal energy seller into the day-ahead energy price.

We also used the same supply assumptions about the generators in earlier Example 3-B in Section 6.3.2 as well, but came to different results (due to different demand assumptions, primarily). Let's also recall the key results from earlier example 3-B, which used the same supply assumptions but in which demand cleared less than the forecast energy requirement. In that example:

- Generator D's energy supply offer at $42/MWh was the marginal offer for energy.
- Energy demand cleared at 700 MWh, which was 20 MWh less than the forecast energy requirement.
- This led to a day-ahead LMP of $39.41/MWh, as the energy market cleared less demand.

- The difference between marginal Generator D's energy supply offer of $42/MWh and the day-ahead LMP of $39.41/MWh, which equals $2.59/MWh, was the Forecst Energy Requirement Price.

- With the Forecast Energy Requirement Price, Generator D's total day-ahead energy payment was $39.41/MWh + $2.59/MWh = $42/MWh.

Now, consider what happens if we combine these two prior examples. Does Generator D still earn only $42/MWh, its energy supply offer price? Or does the market still properly recompense the opportunity cost associated with introducing generation contingency reserve into the market design? We answer these questions next.

► **Assumptions.** In this example, we revisit the same eight generators, Generator A through H, examined previously in Example 4-A in Section 7.5.1*.* We assume there is one generation contingency reserve product, and a demand quantity for generation contingency reserves of 190 MWh. This is the only generation contingency reserve or replacement energy reserve product in the example; we could add more, but that would complicate the insights without altering the conclusions. As in Example 4-A (and Example 3-B), the forecast energy demand is assumed be a 720 MWh.

In this new example, we have changed two things from the prior Example 4-A. First, energy demand is no longer fixed. Instead, we assume there are three priced demand bids for energy. And second, we will introduce the forecast energy requirement and energy imbalance reserve.

For convenience, the energy supply offer prices and quantities (*i.e.,* resource capacities), and their energy option offer prices and quantities, are reproduced in Table 7-16 below. The columns that show Reserve Capability are different from one another; for energy imbalance reserve, this is equal to a generator's energy call option offer quantity. For generation contingency reserve, this may be limited to a lower value (as is the case for Generators C and D), based on the resource's ramp capability (as would be calculated by the ISO).

► **Market outcomes.** The market-clearing outcomes are summarized in the last three columns of Table 7-16. Generators A through D again clear energy supply offers, but only for a total of 700 MW – less than the forecast energy requirement of 720 MWh. Generators D and E clear generation contingency reserve for a total of 190 MWh, equal to that ancillary service's demand. Generator F clears 20 MWh of energy imbalance reserve, closing the gap to the forecast energy requirement.

On the demand side, bids 1 and 2 clear in full, totaling 700 MWh of day-ahead energy purchases. *See* row [13] of Table 7-16.

Table 7-16. Assumptions and Market Outcomes for Example 6-A										
		Supply Offer Assumptions				Reserve Capability		Day-Ahead Outcomes		
		Energy Supply Offers		Energy Option Offers		EIR	GCR	Market Awards		
		Price	Quantity	Price	Quantity	Quantity	Quantity	Energy	EIR	GCR
	Generator	($/MWh)	(MWh)	($/MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)
[1]	A	$0	300					300	-	-
[2]	B	$10	150					150	-	-
[3]	C	$36	150	$2.59	150	150	100	150	-	-
[4]	D	$42	200	$2.59	200	200	100	100	-	100
[5]	E	$60	200	$5.05	90	90	90	-	-	90
[6]	F	$72	50	$5.54	50	50	50	-	20	-
[7]	G	$78	50	$5.82	50	50	50	-	-	-
[8]	H	$210	150					-	-	-
[9]	**Totals**		**1250**		**540**	**540**	**390**	**700**	**20**	**190**
		Demand Assumptions								
		Energy Demand		Forecast Energy		GCR Demand				
		Price	Quantity	Quantity		Quantity				
		($/MWh)	(MWh)	(MWh)		(MWh)				
[10]	Bid 1	$55	500					500		
[11]	Bid 2	$45	200					200		
[12]	Bid 3	$35	100					-		
[13]	**Totals**		**800**	**720**		**190**		**700**		
				Day-Ahead Outcomes						
				Clearing Prices ($/MWh)						
				FERP				LMP	EIR	GCR
[14]				**$5.54**				**$39.41**	**$5.54**	**$5.54**

The marginal offers are shaded in light orange in Table 7-16. The marginal offer for energy is Generator D, as in prior examples 3-B and 4-A. Generator F's energy option offer is marginal for both energy imbalance reserve and generation contingency reserve.

Figure 7-7 shows the supply and demand diagram for the assumptions and results in Table 7-16. The energy supply offers in blue are the same here as in prior Figure 7-4 in Section 7.5.1. The green stair step supply curve shows the energy option offers cleared for generation contingency reserve; as in prior graphic, this starts from the forecast energy requirement. In this figure, the supply of cleared energy option offers for energy imbalance reserve is "squeezed" between the blue supply curve for energy and the green supply curve for generation contingency reserve; to help visual acuity, we have "bubbled" this out to the right in Figure 7-7, in orange.

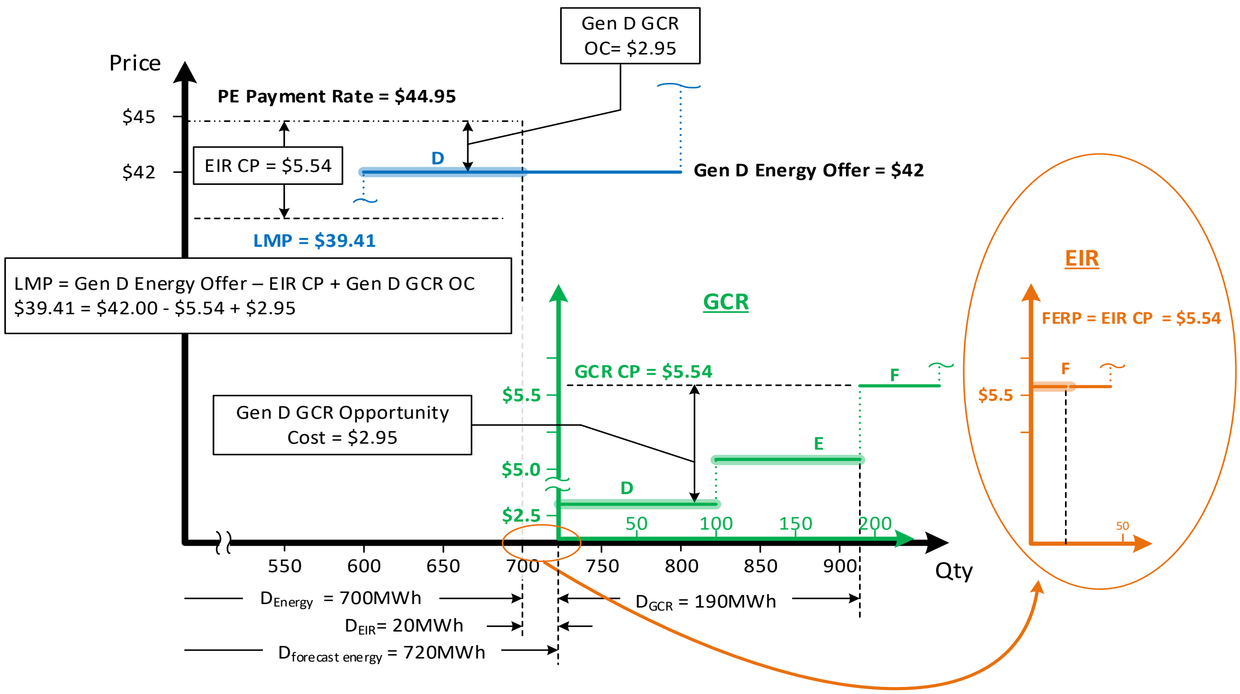

Figure 7-7. Market Clearing Outcomes for Example 6-A

► **Clearing prices.** Here, the clearing price for energy imbalance reserve and generation contingency reserve are straightforward from Figure 7-7. The clearing price for generation contingency reserve is set by Generator F's energy option offer, at $5.54/MWh. Generator F has additional capability to supply another MWh of generation contingency reserve, and is the cheapest additional increment of supply available.

What is the day-ahead LMP? Consider the marginal cost of another MWh of bid-in energy demand, which would increase cleared energy from 700 MWh to 701 MWh. Here there would be a re-dispatch that reduces the marginal cost of an additional increment of bid-in energy demand: each additional MWh of energy that clears from Generator D reduces the amount of energy imbalance reserve procured by a MWh as well. As explained in Section 6.2, the marginal cost of serving another MWh of bid-in energy demand is equal to marginal Generator D's energy supply offer of $42/MWh, minus its energy option offer of $2.59, or $42/MWh – $2.59/MWh = $39.41/MWh. Therefore, the day-ahead LMP is $39.41/MWh.[156]

[156] The re-dispatch here has another step as well: when another MWh of energy demand clears and reduces the quantity of energy imbalance reserve needed by 1 MWh, it is cost-effective to 'switch' 1 MWh of Generator F's award from energy imbalance reserve to generation contingency reserve. That, by itself, costs nothing. Yet, it enables the system to reduce

► **The Main Point.** In this example, Generator D still sells generation contingency reserve profitably, and incurs a $2.59/MWh energy opportunity cost. Efficiency requires it to be paid a price that covers its supply offer price *and* that opportunity cost, which is $42/MWh + $2.59/MWh = $44.95/MWh. But if demand can procure less energy day-ahead than forecast and reduce the day-ahead LMP, how will Generator D get paid the sum of its energy supply offer price and energy opportunity cost?

The answer is: *the Forecast Energy Requirement Price.* Generator D, being a physical supply resource, is paid the sum of the day-ahead LMP and the Forecast Energy Requirement Price. This is $39.41 + $5.54/MWh = $44.95. In other words, the Forecast Energy Requirement Price covers the marginal energy supplier's opportunity cost when it profitably provides other ancillary services – generation contingency reserve and replacement energy reserve.

Let's compare again to the outcome in the earlier example 4-A. There, as here, Generator D was marginal for energy with a supply offer price of $42/MWh. It also incurred an energy opportunity cost of $2.95/MWh because it was inframarginal for generation contingency reserve. To cover its opportunity cost, the day-ahead LMP in Example 4-A was $44.95.

Now, consider the present example. Generator D again is a cost-effective (inframarginal) seller of generation contingency reserve, and incurs an energy opportunity cost of $2.95/MWh by doing so. It needs to be compensated for that opportunity cost, in addition to its energy supply offer price of $42/MWh.

But if the day-ahead LMP were $44.95/MWh, and the real-time LMP were (say) only $42/MWh, demand would have an incentive to not fully procure all 720MWh day ahead. Would that prevent generation from being properly compensated for their marginal cost, including opportunity cost?

With the forecast energy requirement, the answer is no. In this example, the generator's total energy payment – that is, the day-ahead LMP plus the Forecast Energy Requirement Price – is still $44.95/MWh – its marginal energy supply offer and its energy opportunity costs. With energy imbalance reserve, demand arbitrage does not eliminate suppliers' compensation for their intertemporal opportunity costs (that arises due to generation contingency reserve and replacement energy reserve). Rather, it shifts that opportunity cost compensation into the Forecast Energy Requirement Price.

This is illustrated in Figure 7-7. The Forecast Energy Requirement Price not only brings Generator D's total payment up from the day-ahead LMP to its energy supply offer price. It also brings the day-ahead LMP up to the *sum* of its energy supply offer price and its energy opportunity cost. And because it produces that outcome, it is sending the economically-correct price signal to supply, and compensating supply resources appropriately for their opportunity costs.

► **Summary and implications.** The point here is important. Generation contingency reserve and replacement energy reserve create new energy opportunity costs for physical energy resources in

---

Generator D's award of generation contingency reserve by 1 MWh, which has a cost savings to the system of $2.59/MWh. The net marginal cost of serving another MWh of demand is therefore $42/MWh – $2.59/MWh = $39.41/MWh.

the day-ahead market. As discussed in previous examples, an efficient market must pay those opportunity costs, in addition to suppliers' offer prices. That, without any market demand reaction, would tend to raise day-ahead LMPs above real-time LMPs, inviting demand to shy away from participating in the day ahead market.

With the forecast energy requirement and energy imbalance reserve, that situation isn't just countered, it is reversed. In particular, the Forecast Energy Requirement Price will now internalize supplier's energy opportunity costs. As in Section 6.3, payments to physical supply resources at the sum of the day-ahead LMP and the Forecast Energy Requirement Price is the economically-appropriate compensation rate for their energy. That sum will cover both suppliers' marginal energy offer prices, as well as their opportunity costs, when they provide generation contingency reserve and replacement energy reserve.

Viewed more broadly, the forecast energy requirement and energy imbalance reserve, on the one hand, and generation contingency reserve and replacement energy reserve, on the other, are a tightly-coupled, highly interdependent design. Working together, they enable the markets to arbitrage the day-ahead to real-time LMPs – as should occur in a well-functioning market – without depriving supply resources of the economically appropriate compensation that must cover both their energy offer prices and their energy opportunity costs – which, together, will be higher than the LMP.

7.7.2 Example 6-B: Price Convergence.

In Example 6-A, the day-ahead LMP was $39.41/MWh. The real-time LMP, assuming the forecast energy demand is accurate (as we will presently), would be set where the generation energy supply curve intersects it. That price would be $42/MWh.

That price gap creates an incentive for demand (whether virtual or otherwise) to close the price gap, buying more day-ahead. That should not be unexpected with the forecast energy requirement, and it will tend to drive the cleared energy imbalance reserve MWh toward zero.

Two questions typically arise at this point: if the energy imbalance reserve is zero, will the Forecast Energy Requirement Price also be zero? What happens in equilibrium? In this section, we show how this plays out by extending the previous Example 6-A. Our main point is that in equilibrium, the day-ahead and real-time LMP will be equal (in expectation, that is); but the Forecast Energy Requirement Price will not (necessarily) be zero. Rather, it will be economically interpretable as paying physical suppliers their day-ahead energy opportunity costs when, at the day-ahead LMP, it is more profitable to sell energy call options and provide generation contingency reserve or replacement energy reserve.

► **Assumptions.** In this example, we revisit the same eight generators, Generator A through H, and the same assumptions as used in Example 6-A. We assume there is one generation contingency reserve product, and a demand quantity for generation contingency reserves of 190 MWh. The forecast energy demand is 720 MWh.

Table 7-17. Assumptions and Market Outcomes for Example 6-B

		Supply Offer Assumptions				Reserve Capability		Day-Ahead Outcomes		
		Energy Supply Offers		Energy Option Offers		EIR	GCR	Market Awards		
		Price	Quantity	Price	Quantity	Quantity	Quantity	Energy	EIR	GCR
	Generator	($/MWh)	(MWh)	($/MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)
[1]	A	$0	300					300	-	-
[2]	B	$10	150					150	-	-
[3]	C	$36	150	$2.59	150	150	100	150	-	-
[4]	D	$42	200	$2.59	200	200	100	120	-	80
[5]	E	$60	200	$5.05	90	90	90	-		90
[6]	F	$72	50	$5.54	50	50	50	-	-	20
[7]	G	$78	50	$5.82	50	50	50	-	-	-
[8]	H	$210	150					-	-	-
[9]	**Totals**		**1250**		**540**	**540**	**390**	**720**	**0**	**190**

		Demand Assumptions				
		Energy Demand		Forecast Energy	GCR Demand	
		Price	Quantity	Quantity	Quantity	
		($/MWh)	(MWh)	(MWh)	(MWh)	
[10]	Bid 1	$55	500			500
[11]	Bid 2	$45	200			200
[12]	DEC	$42	50			20
[13]	Bid 3	$35	100			-
[14]	**Totals**		**850**	**720**	**190**	**720**

	Day-Ahead Outcomes			
	Clearing Prices ($/MWh)			
	FERP	LMP	EIR	GCR
[15]	**$2.95**	**$42.00**	**$2.95**	**$5.54**

We change one assumption in this revised example. To profit from the day-ahead LMP at $39.41/MWh and (expected) real-time LMP at $42/MWh, we introduce a Decrement Bid (virtual demand bid) that buys day-ahead and sells-out in real time.

For convenience, the full assumptions for this Example 6-B are summarized in Table 7-17.

► **Market outcomes.** The market-clearing outcomes are summarized in the last three columns of Table 7-17. Demand now clears a 720 MWh, equal to the forecast energy demand (*see* row [14]). Generators A through D again clear energy supply offers, now for a total of 720 MWh. Generators D, E, and F clear generation contingency reserve for a total of 190 MWh, equal to that ancillary service's demand. Zero MWh of energy imbalance reserve is cleared.

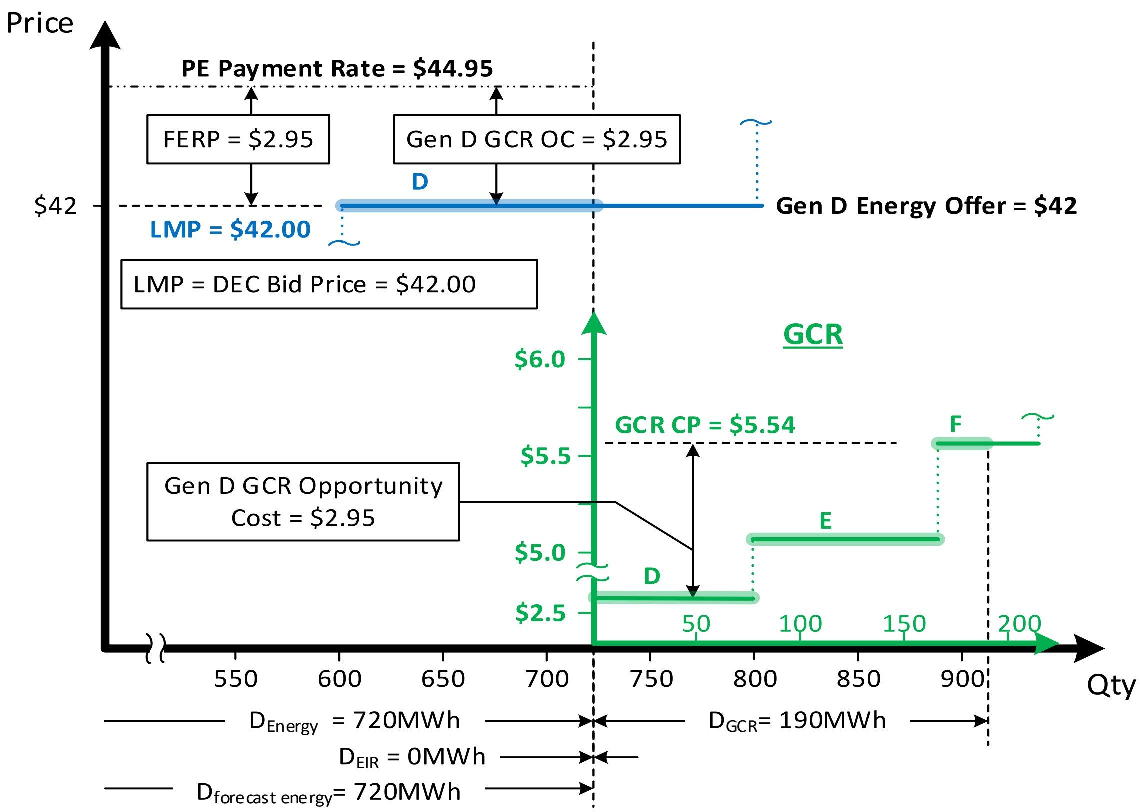

Figure 7-8. Market Clearing Outcomes for Example 6-B

On the demand side, bids 1 and 2 clear in full, totaling 700 MWh of day-ahead energy purchases. The Decrement Bid, priced at $42/MWh, partially clears 20 MWh. *See* row [12] of Table 7-17.

The marginal bids and offers are shaded in light orange in Table 7-17. The marginal offer for energy is Generator D, as in prior examples 3-B and 4-A. Generator F's energy option offer is marginal for generation contingency reserve.

Figure 7-8 shows the supply and demand diagram for the assumptions and results in Table 7-17. The energy supply offers in blue are the same here as in prior Figure 7-4 in Section 7.5.1. The green stair step supply curve shows the energy option offers cleared for generation contingency reserve; as in prior graphic, this starts from the forecast energy requirement.

► **Clearing prices.** Here, the clearing price for generation contingency reserve are straightforward from Figure 7-8 The clearing price for generation contingency reserve is set by Generator F's energy option offer, at $5.54/MWh. As in Example 6-A, Generator F has additional capability to supply another MWh of generation contingency reserve, and is the cheapest additional increment of supply available.

Here the day-ahead LMP is set by demand – specifically, the Decrement Bid at $42/MWh. That is where the energy supply curve and energy demand curves intersect.

What is the Forecast Energy Requirement Price? Since cleared energy imbalance reserve is zero, we have to do the calculations t1o evaluate the incremental cost of a change in the forecast energy requirement. Table 7-18 summarizes the steps. An additional MWh increase in the forecast energy requirement would be satisfied by another unit of energy supply from marginal Generator D. But Generator D must have a demand bid to clear against more energy – and does, in the form of the Decrement Bid at the same price. They match and clear. However, when Generator D sells another MWh of energy, it has one less MWh of generation contingency reserve (as Generator D is capacity limited; *see* Table 7-17). That causes a re-dispatch of generation contingency reserve from Generator D to Generator F, which is the marginal energy option offer. The net cost of this, as shown in Table 7-18, is $2.95/MWh. Therefore, the Forecast Energy Requirement Price is $2.95/MWh.

Table 7-18. Forecast Energy Requirement Price Calculation for Example 6-B

[1]	**Change in Total (Production) Costs for One More MWh of Forecast Energy Demand**		
[2]	+ 1 MWh of energy from Generator D	$42.00	*Energy offer price of FER-marginal Gen D*
			(results in one less MWh of GCR from Gen D)
[3]	+1 MWh of energy from DEC	($42.00)	*Bid price of DEC*
[4]	"Re-dispatch" GCR		
[5]	- 1 MWh of GCR from Generator D	($2.59)	*"Savings" from one less MWh of GCR from Gen D*
[6]	+ 1 MWh of GCR from Generator F	$5.54	*Option offer price to replace the GCR MWh from Gen F*
[7]		$2.95	*Forecast Energy Requirement Price*

► **Implications**. There are three main points to note here. First, demand has a strong incentive, with a forecast energy requirement, to clear energy close to that amount. This will tend to drive cleared energy imbalance reserve toward zero.

Second, even when cleared energy imbalance reserve is zero, the Forecast Energy Requirement Price may not (and commonly may not) be zero. This is because it is covering the energy opportunity cost of the marginal physical supply resource. That energy opportunity cost arises because of the opportunity to provide generation contingency reserve and replacement energy reserve.

Third, this tightly-coupled design – an architectural balance between two economically self-reinforcing mechanisms – requires both energy imbalance reserve and the forecast energy requirement, as well as generation contingency reserve and replacement energy reserve. The former ensures that, in equilibrium, all physical energy supply resources have new compensation with which to undertake costly investments in advance of the operating day. The latter ensures that the resources that the system must rely upon to manage uncertainty during the operating day now have new compensation, and new incentives, to arrange energy supplies even on days when they may not expect to run. And, with the two put together, they jointly ensure that the market properly compensates resources not only for their direct costs of supplying energy, but also for their opportunity costs when they are scheduled to provide any of the new ancillary services instead.

8. Conclusion

The detailed explanations and numerous examples set forth across more than 200 pages in this paper underlie an ultimately simple point. The markets as constructed today contain a significant omission: when it would be to society's benefit (considering both cost and reliability) for a resource to procure fuel in advance, providing important energy security for the region, the resource is not incented to do so.

To date, this problem has not created irreversible risks. And there has been sufficient capability in the system, such that the ISO has consistently been able to rely on the capabilities of resources operating above and beyond their day-ahead schedules to provide the essential reliability services that cover the various energy gaps described herein. And without additional compensation, no less.

But circumstances are changing quickly. Retirements of legacy resources, the burgeoning of renewable resources, and continued gas pipeline constraints will leave the region reliant on 'just-in-time' resources in an unprecedented manner. And this evolving resource mix, with no emphasis on advance fuel arrangements, cannot be relied on in the same way to provide these essential reliability services. The markets must be expanded now to compensate for these services, to ensure they are available as needed.

The Energy Security Improvements detailed in this paper will accomplish this. In a fully market-based and transparent manner, these essential reliability services will be procured and compensated in the day-ahead market. Importantly, this should not be considered a new set of market products. Rather, the Energy Security Improvements create a proper market mechanism for essential services that are needed and procured today, but that are currently procured inefficiently and outside of the markets. With the Energy Security Improvements in place, resource owners will face clear market incentives to arrange fuel in advance of the operating day when it would be beneficial for society for the resource owner to do so.

Attachment C

Affidavit of Dr. Schatzki

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

ISO New England Inc.	)))	Docket No. EL18-182-_____

AFFIDAVIT OF TODD SCHATZKI
ON BEHALF OF
ISO NEW ENGLAND INC.

My name is Todd Schatzki. I am a Principal at Analysis Group, Inc. (“Analysis Group”), a firm that provides microeconomic, strategy and financial analyses.

For more than twenty years, I have worked on energy sector economics, regulation, and policy, including work for government agencies, regulators, market operators, non-profit organizations, and private corporations. This work has involved: market design; economic and financial analysis of energy and environmental regulations and infrastructure changes; ratemaking design and analysis; design and assessment of environmental regulations affecting the electric power sector; and assessment of market competition and market conduct. My work has appeared in both academic and industry journals such as the Journal of Environmental Economics and Management, the Electricity Journal, and Public Utilities Fortnightly, and in publications associated with institutions such as the AEI-Brooking Joint Center for Regulatory Studies and the Harvard Regulatory Policy Program.

I have extensive experience in wholesale power markets in many regions of North America, including work in markets for capacity, energy and ancillary services. I have helped in the review and redesign of market rules used in organized wholesale markets, performed economic analysis of the impacts of proposed market rules, evaluated the rules and procedures for monitoring and mitigation by market monitors in organized markets, evaluated the conduct of market participants with respect to allegations of market manipulation, and assessed economic damages associated with disputes regarding wholesale power contracts. I have worked for market operators in New England ("ISO New England") and New York ("NYISO") on a variety of issues related to market design, market monitoring and the impact of market rule changes under consideration. More broadly, my work has involved many organized wholesale markets, including Alberta Electric System Operator, California ISO, ISO New England, Midcontinent Independent System Operator, Inc., NYISO, PJM Interconnection, and Southwest Power Pool. Across engagements, I have worked on behalf of system and market operators, market monitors, and market participants. I have submitted testimony to federal, state and provincial (Canada) regulatory commissions.

I received a Bachelor of Arts in physics from Wesleyan University, a Masters in City Planning, Environmental Policy and Planning from the Massachusetts Institute of Technology and a Ph.D. in Public Policy from Harvard University. Since receiving my doctorate degree, I have worked with several economic consulting firms, including National Economic Research Associates, Inc., LECG, LLC and now Analysis Group.

In 2019, the Analysis Group was engaged by ISO New England to perform an assessment of the impact of changes to the ISO New England Inc. Transmission, Markets and Services Tariff to implement the "Energy Security Improvements," which are fully described in the accompanying transmittal letter and white paper titled "Energy Security Improvements: Creating Energy Options for New England." I led the effort to perform the impact assessment, the details and results of which are explained in the Energy Security Improvements Impact Assessment ("Impact Assessment") that is included with this filing. I was the principal author of the Impact Assessment, and I declare that the information included in the Impact Assessment is true and correct to be best of my knowledge and belief.

____

Todd Schatzki, Principal, Analysis Group, Inc.

Executed on April 14, 2020.

Energy Security Improvements Impact Assessment

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April 2020

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Glossary of Terms

Abbreviation	Definition
CMR	Current Market Rules
DA LMP	Day-Ahead Locational Marginal Price
DA energy	DA energy award (forward position resulting from day-ahead energy market)
DA energy option	DA energy option (as defined under ESI)
DFO	Distillate fuel oil
EIR	Energy Imbalance Reserves
ESI	Energy Security Improvements
FCA	Forward Capacity Auction
FCM	Forward Capacity Market
FERC	Federal Energy Regulatory Commission
FER	Forecast Energy Requirement
FRM	Forward Reserve Market
GCR	Generation Contingency Reserves
LDC	Local Distribution Companies
NEPOOL	New England Power Pool
RER	Replacement Energy Reserves
RFO	Residual fuel oil
RT LMP	Real-time Locational Marginal Price

Energy Security Improvements Impact Assessment

I. Executive Summary

ISO New England ("ISO-NE") is proposing new market rules intended to address gaps in the current marketplace that have contributed to concerns about the region's ability to handle ongoing and persistent fuel security challenges.[1] Developing long-term solutions to these challenges is important as the concern may worsen with future changes in system and market conditions given resource retirements and policy-driven shifts in energy supplies.

This proposal – the Energy Security Improvements, or ESI – would introduce new day-ahead ancillary services to the market to address identified gap in the market; these ancillary services can improve reliability outcomes but are not appropriately incented by the current market rules. By creating these services, the proposal aims to provide technology neutral market signals aligned with the underlying gap in ancillary services needed to address fuel security concerns. In so doing, ESI aims to improve both reliability and market efficiency by better aligning individual market participant incentives with the value of these reliability services.

This report provides an assessment of the impact of these proposed rules, providing both quantitative and qualitative information about how the ESI proposal would affect economic and reliability outcomes as compared to current market rules. Quantitative analysis is based on simulation of the New England day-ahead and real-time energy markets. Using these simulations, impacts are calculated as the difference in market outcomes with and without the ESI market rules changes in effect. Our quantitative analysis estimates the ESI proposal's expected impacts under particular scenarios, while also demonstrating how ESI would be expected to change market outcomes, including the mechanism through which it would improve incentives for resources to provide energy security that improves system reliability.

Our assessment reaches a number of key findings about the expected impacts of ESI, which we summarize below. These findings reflect both the results of both our quantitative analysis and our qualitative assessment, accounting for both economic and analytic considerations.

1. ESI would create strong financial incentives for resources to maintain more secure energy supplies (e.g., higher levels of energy inventories) and generally improve their ability to deliver energy supplies in real-time. These incentives are created primarily through two channels. First, resources that supply day-ahead energy ("DA energy") are compensated with Forecast Energy Requirement ("FER") payments for helping to meet the FER in the day-ahead market. These FER payments represent a new revenue stream, paid in addition to the day-ahead locational marginal price ("DA LMP"), that compensates resources for their contribution to meeting the FER. Second, the new ESI products allow resources that do not sell DA energy,

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[1] The authors would like to thank the following Analysis Group, Inc. employees for their assistance with modeling and research as part of this project: Kathryn Barnitt, Tyler Farrell, Leigh Franke, Henry Lane, Danny Nightingale, and Abiy Teshome.

but are able to deliver energy in real-time to meet certain reliability needs, to be compensated for providing these services.

Our quantitative analysis focuses on the incentives for units with stored fuel tanks to expand inventory and refuel more aggressively, and for natural gas units with no on-site storage to make contractual fuel arrangements in advance of winter. ESI's incentives may also impact other decisions affecting the availability of real-time energy supplies, such as plant operational decisions (e.g., preservation of reservoir volumes at hydropower units), plant investment decisions (e.g., dual fuel retrofits) and resource entry and exit decisions.

Consistent with its market-based design, ESI's incentives are greatest during periods when energy security risks are most severe, thereby creating the strongest price signals when energy needs are greatest. These incentives to improve deliverability will also be largest for those resources with the greatest risk of having fuel inventories reduced to the point where supply decisions are constrained. Thus, ESI's incentives efficiently target those opportunities to increase inventory that would provide the greatest value to system reliability relative to their incremental costs. The quantitative analysis demonstrates the alignment of ESI's incremental incentives with these periods of need. Moreover, the analysis shows that these incentives are large in magnitude relative to the costs of certain incremental actions (e.g., incremental fuel storage) and are strongest for those resources best able to improve reliability through cost-effective improvements in their ability to supply energy in real-time.

2. By introducing a new market that compensates resources for providing energy security and imposes significant costs if they cannot deliver energy during stressed conditions, ESI would increase incentives to preserve existing energy inventories. With ESI, resources with energy inventories can be compensated for maintaining reserve energy supplies via their sale of day-ahead energy options ("DA energy options") "backed" by this energy. Under current market rules, resources maintaining reserve energy supplies without a day-ahead position are uncompensated. ESI's design creates these incentives because market participants that sell these services via DA energy options face significant costs if they cannot deliver that energy in real-time during stressed system conditions.

3. Under ESI, the day-ahead market would be more likely to clear energy supplies at (or above) forecasted load and any remaining gap between cleared supplies and forecast load will tend to be smaller. This outcome is a consequence of the day-ahead auction clearing mechanism under ESI, which will implicitly assign a cost to not meeting the FER, as the optimization will procure new ancillary services to cover any such "gap" between the forecasted load and cleared DA energy.

4. ESI's collective impact – including points (1) through (3) – would be expected to improve reliability outcomes, particularly during winter periods. ESI would support delivery of energy in real-time to customer load, supply real-time operating reserves and maintain reliable operations during prolonged system contingencies. Although our quantitative analysis is not designed to precisely analyze system reliability, it quantifies certain aspects of fuel system operations to demonstrate ways in which ESI can reduce stress on fuel systems relied on for energy delivery. The analysis shows that incremental inventoried energy incented by ESI would reduce use of the natural gas pipeline system during tight market conditions, increase aggregate fuel oil inventories, and reduce the rate at which fuel supplies are depleted under stressed conditions. These results are consistent with more reliable electricity system outcomes, particularly during periods of greater fuel system stress.

5. ESI would be expected to improve efficiency and lower production costs under stressed market conditions when the increase in energy inventory reduces energy production from less efficient suppliers and higher cost fuels. Improvements in market efficiency to meet customer loads are expected through improved energy deliverability in tight market conditions, which helps to address the underinvestment in energy security under current market rules (identified as the "misaligned incentives" problem in ISO-NE's "Energy Security Improvements" White Paper) and more efficient unit commitment to meet real-time operating reserves.[2] Under stressed conditions, production costs are conservatively estimated to fall by $19 million and $36 million for the cases evaluated. These reductions in production costs are separate from the improvements in reliability that ESI would also be expected to create.

* * *

While generating these efficiency and reliability benefits, the ESI proposal is also expected to have consequences for payments by load and net revenue to resource owners in the ISO-NE energy markets. **Table 1** provides the estimated changes in total payments during the three winter months for each winter Central Case.

Table 1. Summary of Impacts to Total Payments for Winter Cases

	Frequent Case		Extended Case		Infrequent Case	
Product / Payment	**Payments ($Million)**	**ESI % Change**	**Payments ($Million)**	**ESI % Change**	**Payments ($Million)**	**ESI % Change**
Change in Energy & RT Operating Reserves	-$183	-4.5%	-$214	-7.8%	-$41	-2.4%
Net DA Ancillary Services	$66		$32		$15	
FER Payments	$250		$113		$61	
Change in Total Payments	$132	3.2%	-$69	-2.5%	$35	2.0%

With ESI, aggregate payments by load (to suppliers) would be expected to increase during periods when stressed market conditions are uncommon or infrequent. In the winter months, the estimated change in payments is $35 million over the 3-month winter in the Infrequent Case. In the non-winter months, the estimated changes in payments is $89 million or $125 million (depending on the severity of non-winter market conditions).

Under stressed market conditions, total payments by load (to suppliers) could increase or decrease. The impact on payments under stressed conditions depends on a combination of factors, including the nature of the stressed conditions (e.g., frequency and duration of stressed conditions) and the amount of incremental energy inventory incented by ESI, as this inventory can lower energy prices, particularly during stressed market conditions. In the winter months, this results in an increase in payments of $132 million in the Frequent Case, and a decrease in payments of $69 million in the Extended Case.

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2 ISO New England, Energy Security Improvements: Creating Energy Options for New England, April 15, 2020 ("ESI White Paper").

Overall, aggregate customer payment impacts are modest relative to all ISO-NE markets. Annual impacts range from $20 million to $257 million annually, combining individual winter and non-winter Central Cases, representing a 0.2% to 2.1% increase in total customer payments.

Aggregate impacts to supplier net revenues tend to be the opposite of payments by load. Increased revenues to resource owners generally translate into increased net revenues, although there are some increased costs associated with ESI implementation (e.g., increased fuel inventory holding costs). Thus, in general, increased payments by customers would generally translate into increased net revenues to resource owners, while decreased payments by customers would generally translate into decreased net revenues.

Impacts on net supplier revenues vary across resource types. Net revenue impacts vary across resource types, although direction of these impacts under particular market conditions (i.e., whether net revenues increase or decrease) is generally the same across different resource types.

Estimated changes in payments (and generator net revenues) reflect only changes in energy and ancillary services market outcomes, and do not consider impacts on other wholesale markets such as the Forward Capacity Market ("FCM") or Forward Reserve Market ("FRM").

II. Introduction

ISO-NE is proposing new market rules intended to address a number of gaps in the current marketplace that have contributed to on-going concerns about the region's ability to maintain the necessary fuel security for reliable operations, particularly as the region's fuel and electricity infrastructure evolves in response to policy and market forces. This proposal – the Energy Security Improvements, or ESI – would introduce new day-ahead ancillary services to the market to address these gaps. The proposal develops day-ahead ancillary service products to address identified gaps in energy supplies that can improve reliability outcomes but are not currently incented by the market. By creating these services, the proposal also aims to improve efficiency by better aligning individual market participant incentives with the region's need for energy supplies during tight market conditions.

This report provides an assessment of the impact of these proposed rules. It provides both quantitative and qualitative information about how the ESI proposal would affect economic and reliability outcomes as compared to current market rules. This information has been developed through a consultative process, with input from both ISO-NE and New England Power Pool ("NEPOOL") stakeholders. Preliminary results were shared with NEPOOL stakeholders in a series of presentations that also provided information on the research approaches, data and assumptions we intended to use. Through this process, we received feedback from stakeholders on these approaches, data and assumptions, and incorporated this information into our assessment, when appropriate. We also received requests for quantitative analysis of impacts under particular assumptions that were considered when developing the set of Scenarios that we analyze in our scenario analysis.[3] Our final set of Scenarios addresses a large fraction of these requests and reflects subsequent communications with stakeholders about which requests were the highest priority among scenarios identified in written requests.

A. Assignment

Analysis Group has been asked to develop an Impact Assessment for the ESI market rule changes being proposed by ISO-NE. Our Impact Assessment is designed to provide both quantitative and qualitative assessment of the likely impacts of the ESI proposal to provide ISO-NE and stakeholders with information about possible impacts of the proposed rule changes (relative to current rules), including the potential efficiency and reliability benefits, costs, impact on consumer payments, and other changes relevant to policy goals. In particular, our Impact Assessment provides information on changes to customer payments and production costs; changes to incentives to market participants to take steps to improve their ability to supply energy in real-time; changes to fuel system operational outcomes that have implications for system reliability; and other expected energy market impacts.

Our assessment includes quantitative analysis of the impacts of the ESI proposal on energy market outcomes based on market simulations. Rather than trying to evaluate expected outcomes across a wide range of probability-weighted scenarios, this work both evaluates particular deterministic winter scenarios, and

[3] "Energy Security Improvements (ESI) Impact Assessment - Extension Priorities." NESCOE. October 15, 2019. "Scenario Request for Impact Assessment for Long-Term Energy Inventory Security Proposal." Massachusetts Attorney General's Office. August 6, 2019.

illustrates particular mechanisms by which ESI may change market outcomes, drawing on particular examples from the model simulations. Our assessment does not consider impacts to other New England markets, including the FCM and FRM.

B. Overview of Energy Security Improvements

ISO-NE is proposing the ESI market rule changes to address persistent fuel security concerns within the New England region that create adverse risks to reliable system operations. Developing robust long-term solutions is important as these challenges may become more significant with future changes in system conditions given resource retirements and policy-driven shifts in energy supplies. These fuel security concerns were a focus of an Order from the Federal Energy Regulatory Commission ("FERC"), which directed ISO-NE to submit "Tariff revisions reflecting improvements to its market design to better address regional fuel security concerns."[4] The ESI market rule changes are proposed in response to this directive.

The ESI proposal is summarized in the ESI White Paper, and is defined further in subsequent presentations to the NEPOOL Markets Committee. ESI is designed to provide a long-term, market-based and technology-neutral solution to existing concerns with the region's markets, including persistent energy security challenges. To this end, the ESI proposal introduces multiple new ancillary services to address different gaps in the current services procured day-ahead and thereby improve reliability outcomes. Through new payment streams and the financial positions it creates for market participants providing the new ancillary services, ESI creates new incentives for resource owners to take actions (e.g., procuring fuel) to increase the likelihood that they are able to deliver energy in real-time. These new services can also better align resource incentives to maintain fuel security with the benefits these arrangements provide. In particular, the ESI White Paper identifies a "misaligned incentives" problem that occurs when a resource's private incentives to improve its ability to provide energy supply in real-time do not align with society's incentives for market participants to undertake such arrangements.

Specifically, ESI proposes to introduce the following three new ancillary services, and compensate resources that provide each accordingly:

- ***Energy Imbalance Reserves ("EIR") and Forecast Energy Requirement ("FER").*** ESI imposes an FER, which requires that EIR be procured to cover the gap, if any, between (1) the expected real-time load, as estimated prior to clearing the day-ahead market, and (2) the supply of physical energy cleared in the day-ahead market. At present, ISO-NE ensures reliable operations if there is a gap between the forecast load and the cleared day-ahead physical energy supply through supplemental reliability commitments that are made after the day-ahead market is run. However, this service (through ramping capability from committed units, reliance on fast start units, or incremental commitments, if needed) is currently uncompensated.

  Along with the EIR, ESI would also compensate day-ahead physical energy supply that contributes to meeting the FER. The FER price paid to DA energy is set to either (1) the (marginal) savings from

[4] ISO New England Inc., 164 FERC ¶ 61,003 at P 2 (2018).

supplying DA energy, calculated as the avoided cost of a DA energy option to meet the FER constraint, or (2) the (marginal) cost of supplying additional DA energy (e.g., the difference between marginal supply and demand offers) if cleared DA energy exactly meets the forecast load. At this price, the resource is no worse off from supplying DA energy as compared to supplying EIR, thus providing incentives to offer supply of DA energy and DA energy options at the respective opportunity costs.

- ***Generation Contingency Reserves ("GCR").*** With GCR, ESI provides an approach to procuring, in the day-ahead energy and ancillary services market, the resource capabilities that ISO-NE currently designates and maintains in real-time for operating reserves. This ensures that adequate energy supplies are available to supply these operating reserves, thus allowing operators to meet system contingencies in real-time. In addition, day-ahead procurement of real-time operating reserves would improve market efficiency by ensuring that day-ahead commitments reflect a co-optimized procurement of energy and operating reserves.

- ***Replacement Energy Reserves ("RER").*** The RER seeks to ensure that there are sufficient energy reserves to maintain reliable system operations in the event of an extended resource contingency. In particular, the RER is designed to allow real-time operating reserves to be restored after a system contingency.[5]

Together, procurement of these new ancillary services would improve the system's ability to respond to unanticipated, real-time stressed system conditions that create adverse reliability risks, and would provide price signals to the market that incentivize market participants to take steps to improve fuel security and resource performance.[6]

Except for FER payments to resources that supply DA energy, the new ancillary services would be delivered through provision of "real" energy options. Market participants would submit offers to supply an energy (call) option, specifying the minimum price they are willing to be paid to accept the energy offer obligation. A standardized, uniform energy option will be procured for all ESI products. The energy option is structured as a call option, where, in exchange for this up-front payment, the supplier pays (credits) load the difference between the real-time locational marginal price ("LMP") and a pre-determined strike price, if that difference is greater than zero. That is, the per-MWh payment – or "closeout cost" – is:

Closeout cost = maximum (0, real-time LMP – strike price).

Ability to supply each of the ESI products depends on each resource's physical energy capabilities to ensure that the option for energy supply being procured is consistent with the underlying real-time need associated with each product. Thus, the ability to supply GCR products reflects the same operational requirements as real-time operating reserves; the ability to supply EIR reflects operational requirements consistent with the

5 ISO New England, "Energy Security Improvements: Market-based Approaches, Replacement Energy Reserves," January 14-15, 2020. https://www.iso-ne.com/static-assets/documents/2020/01/a5_a_iii_esi_replacement_energy_reserves_rev1.pptx

6 Mark Karl and Peter Brandien, Letter to NEPOOL Markets Committee, December 4, 2019. https://www.iso-ne.com/static-assets/documents/2019/12/a6_c_i_memo_re_how_market_improvements_address_fuel_security.pdf

energy being available within 60 minutes, and the ability to supply RER products reflects longer-lead time (90- or 240-minute) operational capabilities.

Under ESI, ISO-NE will co-optimize the procurement of energy and energy options in the day-ahead market to clear supply offers and demand bids, ensure load balancing, and meet new ESI product constraints. While the proposal introduces new products to the day-ahead market, market-clearing of New England's real-time energy and ancillary services would be unchanged.

III. Approach to Impact Assessment

The Impact Assessment reflects both *quantitative analysis* of changes in outcomes from our economic model and *qualitative assessment* of factors not captured by our quantitative analysis. Quantitative impacts are estimated through a simulation of the New England day-ahead and real-time energy markets (including real-time reserves). The production cost model used to simulate the market will be run two times, once using assumptions consistent with market-clearing under Current Market Rules (CMR), where the new ancillary services are not procured in the day-ahead market, and a second time using assumptions consistent with market-clearing under the ESI, where these new ancillary services are procured.[7] ESI's impacts are estimated to be the difference in outcomes between the ESI case and the corresponding CMR case, as this difference represents the (positive or negative) incremental impacts associated with the market rule change. For example, our estimate of ESI's impact on total customer payments is the total payments under the ESI case minus the total payments under the CMR case. Using this approach, we develop estimates of changes in economic outcomes (e.g., prices, production costs, total payments) and changes in system operational outcomes reflective of reliability impacts (e.g., fuel inventory, reserve shortages).

The quantitative analysis is performed by evaluating individual scenarios under assumed market conditions. These scenarios do not represent forecasts or predictions of future outcomes. Instead, these deterministic scenarios are intended to represent potential market and resource conditions that might reasonably arise in the future, and provide an indicative snapshot of ESI's impacts under these conditions. The scenario analysis also does not provide an indication of ESI's probability-weighted expected impacts, as the model does not weight the likelihood that the different scenarios being evaluated, or the many potential scenarios that are not evaluated, will occur.

The quantitative analysis considers different Cases reflecting potential future market and system conditions, and different levels of stress on the fuel supply systems. We consider both winter month and non-winter month cases. Much of our quantitative analysis focuses on ***impacts in winter months***, because energy security currently poses the most pressing challenges to New England in the winter months. However, we also evaluate ESI's impacts during non-winter months as the ESI proposal introduces these new day-ahead ancillary services across all twelve months for a combination of reasons, including energy security concerns that could become more pronounced during non-winter months as the region's resource mix and energy infrastructure

7 Throughout the report, the acronym CMR is used when referring to the specific "case" we analyze, while the phrase "current market rules" is used when referring to the ISO-NE energy market's current market design and rules.

evolves, and the possibility that the "misaligned incentives" problem would otherwise reduce market efficiency during non-winter months.[8]

For the winter months, we evaluate three levels of market and system stress based on historical New England winters:

- ***Frequent Stressed Conditions ("Frequent Case").*** The Frequent Case is based on market conditions from the winter of 2013/14. This winter experienced multiple, shorter periods with fuel system constraints, driven in large part by numerous cold-snaps.

- ***Extended Stressed Conditions ("Extended Case").*** The Extended Case is based on market conditions from the winter of 2017/18. This winter experienced one extended period with fuel system constraints, which occurred during a long cold-snap in late December and early January.

- ***Infrequent Stressed Conditions ("Infrequent Case").*** The Infrequent Case is based on market conditions from the winter of 2016/17. This winter experienced particularly mild temperatures and no periods of stressed conditions. One indicator of the mildness of these conditions was that day-ahead natural gas prices at Algonquin Citygate never exceeded $13 per MMBtu over the entire winter.

Impacts in non-winter months are evaluated through two Cases, also based on historical non-winter periods:

- ***Severe Stressed Conditions ("Severe Case").*** The Severe Case reflects more stressed market conditions (e.g., high customer loads), based on the 2018 non-winter months.

- ***Moderate Stressed Conditions ("Moderate Case").*** The Moderate Case reflects typical non-winter conditions without periods of more stressed market conditions, based on the 2017 non-winter months.

These Cases provide information on ESI's economic impacts but do not analyze changes in operational metrics that signal improvements in reliability.

While these winter and non-winter Cases are based on historical periods, load and supply conditions are updated to be more consistent with a future year, assumed to run from December 1, 2025 to November 30, 2026. More specifically, they assume a future resource mix that includes current resources in the fleet and announced retirements and fuel (natural gas) availability consistent with current infrastructure and potential retirements (e.g., Distrigas LNG terminal in Everett, Massachusetts). Other assumptions are based on actual market conditions from the historical periods identified above, including loads, certain resource supplies (such as, wind and solar), natural gas prices and availability of natural gas supplies to the electricity sector (given demand from natural gas Local Distribution Companies ("LDCs")).

Our core analysis – or Central Case – evaluates each of these different market conditions (or levels of system stress) in substantial detail, and the results from these Cases are presented in **Sections IV.A** (winter) and **IV.B**

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8 ISO New England, "Energy Security Improvements," ISO Discussion Paper, Version 1, April 2019.

(non-winter). In addition, we analyze multiple Scenarios in **Section IV.C** that alter particular assumptions related to ESI market design, system resources, fuel supplies and costs.

The Central Cases are not intended to represent "business as usual" cases, but plausible future *scenarios* consistent with the current mix of resources and infrastructure in New England. Consistent with this scenario-based approach to our analysis, we do not assign probabilities to each Case, particularly as these Cases represent a subset of the range of possible future market conditions. It is beyond the scope of this analysis to attempt to assign probabilities to these Cases. While there is substantial weather data available that might support the assignment of probabilities to particular weather conditions, ESI impacts reflect not only factors driven by weather conditions, such as electricity market loads and natural gas supplies, but many other factors, such as the retirement and entry of energy infrastructure, that will depend on market, regulatory and policy outcomes that are difficult to forecast.

A. Production Cost Model: Overview

The New England energy market is analyzed using an integrated production cost model that captures key features of the markets to provide reasonable measures of the impacts of the proposed ESI rules. This model incorporates both day-ahead and real-time energy markets, real-time ancillary service markets for 10- and 30-minute operating reserves, opportunity cost bidding options allowing market participants to account for limited energy, and the proposed ESI day-ahead ancillary services.[9]

The production cost model simulates market clearing consistent with a competitive wholesale energy market. The model maximizes social welfare[10] as reflected in demand bids and supply offers, while satisfying other physical system requirements, including supply-load balancing and procurement of various ancillary services in day-ahead and real-time.

The model simulates market-clearing across all 24 hours of each day. Each day's market is simulated sequentially, with the outcomes of real-time market clearing in each day affecting the supply offers in subsequent days, given limited fuel supplies and the constraints associated with fuel replenishment. Day-ahead and real-time market-clearing is coordinated, in the sense that the consequences of supply decisions in real-time affect day-ahead offers in a manner consistent with market participants' reasonable expectations about inventories when submitting day-ahead offers.

Figure 1 provides a schematic for the model's structure. The model's core includes algorithms to replicate market clearing in the New England day-ahead and real-time energy markets. The algorithms account for key features of the markets as they operate under current market rules and as they would operate under ESI, including supply-load balancing and ancillary service constraints. The algorithms account for some, but not

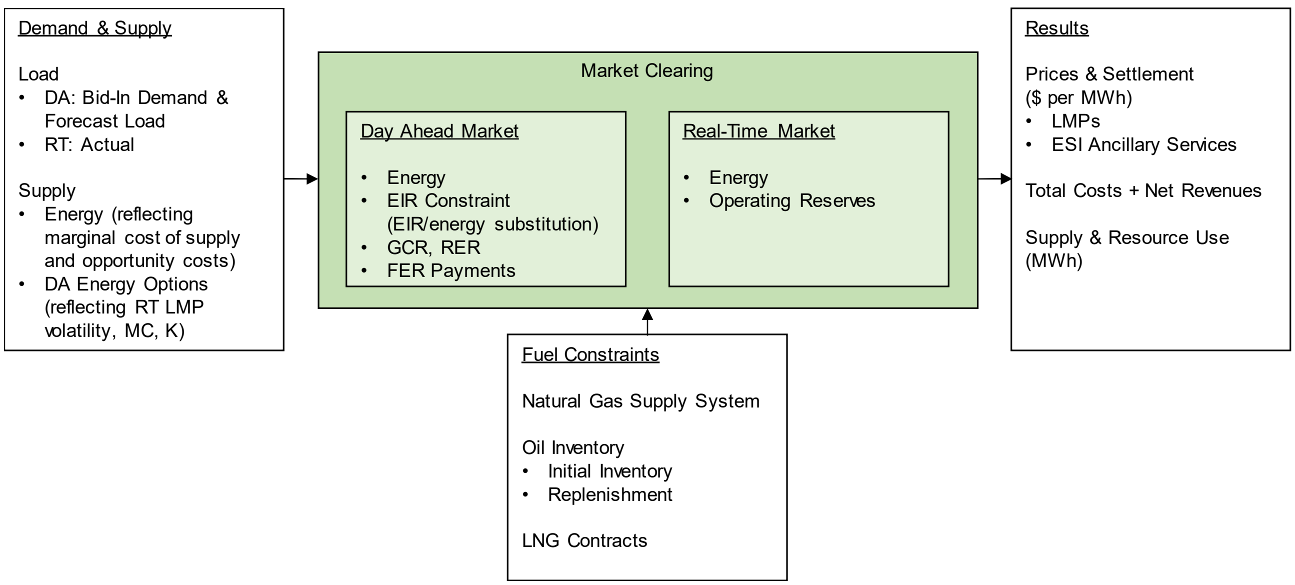
9 The analysis in this report does not account for locational constraints and therefore simulates a single DA and RT LMPs for the entire region. As a result, when the report refers to the DA or RT LMP, this is the price all energy supply is paid, and energy options are settled at the RT LMP.

10 Social welfare in the day-ahead market reflects the sum of bid-in demand net of the sum of supply offers for energy and ancillary services needed to meet all day-ahead market constraints, accounting for any penalty factors associated with failure to meet particular constraints. This welfare calculation is discussed in more detail in the appendix.

all, resource operational limitations. For example, the model does not account for unit commitment logic, through which certain intertemporal parameters (for example, start-up costs, minimum run-time, and minimum down-time) are accounted for. Thus, our analysis will not quantify all factors that determine energy and ancillary service positions, or all changes in production costs associated with ESI.

Information on supply offers and demand bids are inputs to the model based on each Case's assumptions. In addition, information about fuel constraints is captured by the model, including natural gas supply available to the electricity sector, fuel oil inventories, and any forward LNG contracts. These fuel constraints are dynamically determined through the modeling of fuel inventory, including replenishment. The model provides outputs, to be used for analysis, including product prices (LMPs, ancillary service prices), day-ahead and real-time supply of energy and ancillary services, and fuel inventories.

Figure 1. Overview of Modeling Approach: Model Components



B. Day-Ahead and Real-Time Markets

Within the **day-ahead market module**, market participants submit supply offers to sell both energy and DA energy options and demand bids to purchase quantities of energy. The model clears these offers to sell and bids to buy such that welfare is maximized, supply equals demand, and, in the ESI cases, ESI ancillary service constraints are met over all hours of the day.[11] Offer prices and quantities for each resource are dynamically bid into the model based on case and resource-specific assumptions (e.g., fuel prices, variable operating costs) and the results of market clearing in prior days (e.g., including an opportunity cost as appropriate to account for limited fuel inventory). Bid prices for load reflect the quantity of energy that the market (including physical load and virtual load) is willing to purchase at different energy prices.

[11] As we describe below, the model includes shortage prices for all day-ahead and real-time ancillary services consistent with current market rules or the ESI proposal.

The **real-time market module** is designed similarly, with three key differences. First, this module includes real-time operating reserves instead of ESI products, consistent with the current market design, which would be unchanged under ESI. Second, all offers in the real-time market reflect actual fuel inventory available given previous days' generation and refueling, rather than assuming fuel inventory based on the resource's day-ahead awards. Third, electricity demand is inelastic (i.e., set at a fixed level in each hour).

The model evaluates outcomes in winter months and non-winter months. In general, model operations, assumptions and data are similar for winter and non-winter months, but we identify differences when they arise in the descriptions below.

1. Day-Ahead Energy Market Demand

We analyze three future winter cases for the year 2025/26, reflecting Frequent, Extended, and Infrequent stressed conditions. These Cases are based on weather and load patterns from the three-month (December through February) winters of 2016/17, 2017/18, and 2013/14, respectively. We also model two future non-winter cases, Moderate and Severe, based on weather and load patterns from the nine-month non-winter period (March through November) for 2017 and 2018, respectively. In each Case, weather patterns and other factors affect both electricity demand and natural gas supply available to the electricity sector, given LDC (non-electricity) demand. Gas supply is discussed in **Section III.C.1**.

Bids to buy DA energy are based on historical bid-in demand from physical load, virtual trades, and pumped storage. Bid-in demand is modeled as a sloped demand curve (with discrete quantities at different price levels) in each hour, so the market awards hourly DA energy positions to the demand bids (and supply offers) that maximize welfare while meeting the various energy balance and ancillary service constraints. The day-ahead load forecast and actual real-time load (demand) are based on historical data from the respective year for each Case. These data provide the hour-to-hour load patterns that are used in the future cases.

To calculate future (2025/26) hourly values for the load forecast, day-ahead demand bids, and real-time energy load, we scale the historical values so that future bids and loads are consistent with the forecast peak load and forecast adjusted total energy from the 2019 CELT Report for the year 2025/26.[12] For each Case, **Table 2** lists the historical base year used as the basis for hour-to-hour load patterns, and the forecast peak load and adjusted total energy values (from CELT) used as the benchmarks for future loads.

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[12] ISO New England. (2018, September 5). 2018-2027 Forecast Report of Capacity, Energy, Loads and Transmission (CELT Report). Retrieved from https://www.iso-ne.com/system-planning/system-plans-studies/celt/ (ISO New England, 2018)

Table 2. Summary of Load by Future Winter Case

Season	Case	Base Year	CELT Scenario	Peak Load	Total Energy
Winter	Infrequent Case	2016/17	20/80 Peak Load Unmodified total energy for 2025/26	19,250 MW	31,525 GWh
	Extended Case	2017/18	50/50 Peak Load Predicted total energy for 2025/26 +1%	19,436 MW	31,840 GWh
	Frequent Case	2013/14	80/20 Peak Load Predicted total energy for 2025/26 +2%	19,837 MW	31,156 GWh
Non-Winter	Moderate Case	2017	50/50 Peak Load Unmodified total energy for 2026	24,315 MW	88,287 GWh
	Severe Case	2018	80/20 Peak Load Predicted total energy for 2026 +1%	25,412 MW	90,053 GWh

Day-ahead bid-in demand varies between the CMR and ESI cases. In the CMR cases, bid-in demand is based on historical bid-in demand, calibrated so that the market clears at an energy price consistent with historical day-ahead energy market outcomes (that in principle are consistent with expected real-time market outcomes), while also accounting for changes in demand from historical to anticipated future levels. In the ESI cases, bid-in demand also accounts for the shift in demand that would occur due to the impact of ESI on energy prices and the market response given arbitrage opportunities. We discuss this further in **Section III.B.5**.

2. Day-Ahead Ancillary Service Product Demand for ESI Runs

In the runs where ESI is assumed to be in effect, the model simulation clears supplies of day-ahead energy options to meet the new ESI constraints. This simulation co-optimizes the market-clearing of all products in the day-ahead market, including energy and each of four ESI products – GCR10, GCR30, RER, and EIR.[13] We model hourly requirements for GCR10, GCR30, RER, and EIR.

For ***GCR***, we model GCR10 and GCR30, but do not account for separate spinning and non-spinning requirements for GCR10. The model assumes the required quantities of GCR10 and GCR30 are 1,600 and 2,400 MW, respectively, levels that are consistent with the ESI proposal. While, in practice, these values will vary from day to day depending on each day's first- and second-contingencies, we expect this variation to be sufficiently small that assuming a fixed requirement is unlikely to meaningfully affect estimated impacts. Committed GCR10 quantities cascade, such that they can contribute to meeting both the GCR10 and GCR30 requirements.

For ***RER***, we model a single RER product, combining the RER90 and RER240 products.[14] The model assumes a fixed requirement of 1,200 MW in each hour for both RER90 and RER240. This requirement cascades with the GCR10 and GCR30 requirements, such that the combined requirement of GCR10, GCR30, and RER is 3,600 MW.

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[13] The model collapses the two RER products proposed by ISO-NE into a single product for simplicity.

[14] This modeling assumption will therefore compensate all resources that provide the RER90 or RER240 product at a single price that is more in line with the RER240 product. In practice, it may therefore understate the compensation to resources that provide the RER90 product in hours when this product would be priced above the RER 240 product.

*For **EIR**,* rather than assuming a fixed value, the requirement is modeled endogenously as a function of cleared energy supply – which is solved simultaneously – and the ISO-NE load forecast, which is fixed in each hour. We describe this constraint in further detail below, in **Section III.B.5**.

ESI product awards are limited by resource-specific characteristics given each resource's ability to provide each ESI service. Offline capability reflects a unit's Claim10, Claim30, "Claim60", or "Claim240" capability to provide GCR10, GCR30, EIR, and RER, respectively.[15] A unit with a DA energy award can also supply ESI products through the unit's ramp capability, and the model's logic is designed such that this ramp capability can receive an ESI award only when it is also supplying DA energy (in quantities consistent with a plant's minimum load).[16] Data on Claim10, Claim30, "Claim60", and "Claim240" capability are provided by ISO-NE.

The analysis also assumes ESI awards are limited by the availability of fuel to physically support the DA energy option. At the resource level, cleared DA energy option quantities are limited to the resource's available energy inventory. For example, oil-only units will only sell a DA energy option if they have fuel in inventory to cover this position. At the system level, the total supply of ESI products awarded to gas-only resources is limited by the hourly supply of natural gas available through the pipeline system to the electricity sector.

The prices for each ESI product is limited by administratively determined penalty factors. Penalty factors cap the price for each ESI product, including circumstances when there is insufficient supply of eligible DA energy options to meet a particular requirement. **Table 3** provides the modeled penalty factors (per MWh), which align with ISO-NE's proposed market design:[17]

Table 3. ESI Day-Ahead Ancillary Service Penalty Factors

Ancillary Service Product	Penalty Factor (per MWh)
RER	$100
GCR30	$1,000
GCR10	$1,500
EIR	$2,929

3. Day-Ahead Energy Market Supply

Our analysis assumes the operation of resources currently in the New England market, defined to be resources that have cleared the 13th Forward Capacity Auction (FCA 13) but have not submitted retirement notifications for FCA 14. This assumes the retirement of the Mystic 8 and 9 generation facilities that currently have a cost-

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15 In this report, Claim10, Claim30, Claim60, and Claim240 represent the capacity in MW that a unit can provide from an offline state in 10, 30, 60, and 240 minutes, respectively. While Claim10 and Claim30 are currently defined parameters that correspond with the procurement of operating reserves, Claim60 and Claim240 are not currently defined (thus, placed in quotations), but are used to reflect the analogous parameters for 60- and 240-minute capability to deliver energy within 60 and 240 minutes, respectively.

16 For simplicity, resources are modeled as either "claim" (cold start) or "ramp" (must be providing energy) eligible.

17 The penalty factor for RER is set to $100 per MWh, which corresponds to the penalty factor for RER240. The penalty factor for RER90, which is not modeled in this analysis is currently proposed to be set to $250 per MWh.

of-service contract.[18] **Table 4** summarizes the mix of resources by resource-type, reporting total capacity by category for the winter months, based on winter claimed capability. The analysis of non-winter month relies on summer claimed capability. The fleet of resources are assumed to be the same under CMR and ESI, although certain gas-only resources are categorized differently – under ESI these resources have a forward LNG contract, whereas under CMR they do not.

Table 4. Future Resource Mix Scenarios, Winter Months, Capacity (MW)[19]

	CMR	ESI
Natural Gas Fired Resources		
Natural Gas with Oil Dual Fuel	7,928	7,928
Natural Gas Only	8,603	7,987
Natural Gas with LNG Forward Contract	0	616
Natural Gas Fuel Cell	21	21
Oil Only	6,304	6,304
Coal	535	535
Nuclear	3,344	3,344
Hydroelectric Resources		
Hydro: Pondage	1,241	1,241
Hydro: Run-of-River	749	749
Pumped Storage	1,778	1,778
Wind Resource		
Land Based Wind	1,401	1,401
Offshore Wind	832	832
Solar	1,671	1,671
Biomass/Refuse	849	849
Battery Storage	458	458
Price Responsive DR	285	285
Total	**35,998**	**35,998**

Energy-supplying resources are modeled as either **optimized resources** or **profiled resources**.

Optimized resources submit energy market offers in each hour at a price reflecting their marginal cost of production. These resources include fossil fuel resources, biomass, fuel cells, price responsive demand, and imports.[20] Resource offers generally reflect the same cost factors in winter and non-winter months, and the total day-ahead supply each resource can clear in the market – including DA energy and ESI products – is limited to its seasonal claimed capability, which can vary between summer and winter. In addition, the quantity

[18] 164 FERC ¶ 61,022, Order, July 13, 2018

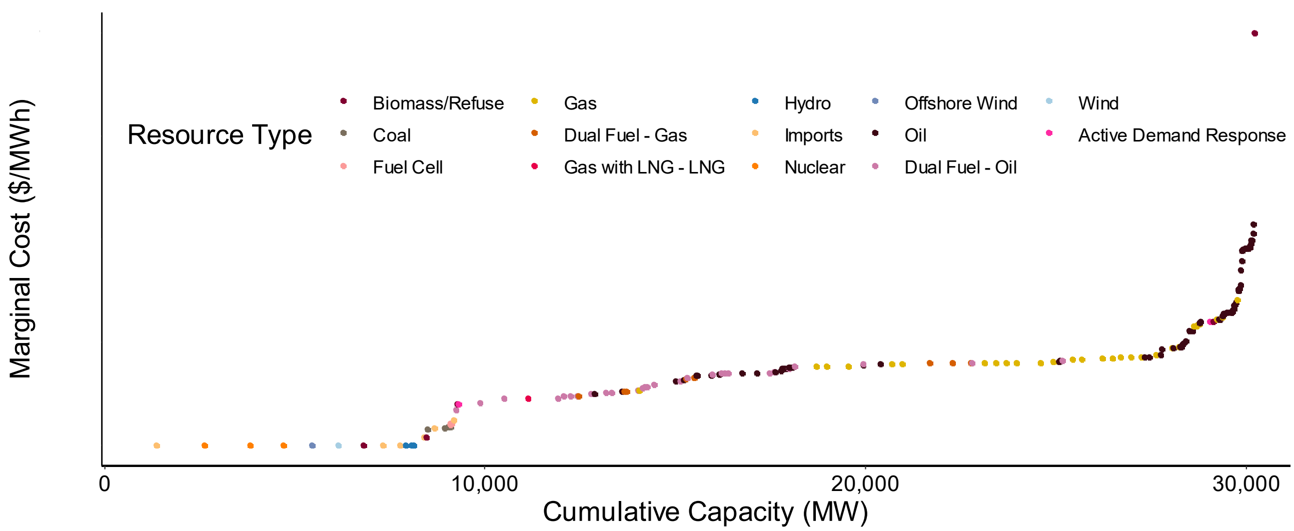
[19] Capacity is based on FCA 13 results (excluding resources that have submitted FCA 14 retirement notifications). Dispatched units assume seasonal claimed capability and profiled units assume nameplate capability from the 2019 CELT Report. In addition to these FCA-cleared units, future supply includes 886 MW of new solar capability, 458 MW of battery storage, and 1,339 MW of wind capability (507 MW onshore, 832 MW offshore). The winter month analysis assumes winter claimed capability and the non-winter month analysis assumes summer claimed capability. Additional information on assumed retirements, dispatched units, and profiled units is provided in the appendix.

[20] The full set of dispatched resources are: Gas, Oil, Coal, Nuclear, Biomass/Refuse, Imports, Fuel Cell, and Price Responsive Demand.

each resource can supply is also adjusted for its average forced outage rate. For example, a 100 MW unit with a 5% forced outage rate is assumed to be capable of supplying 95 MW across all hours. Market-clearing also reflects resource-specific offers for supplying a DA energy option, as discussed further in **Section III.B.4**.

Supply offers from optimized resources are used to create a supply curve, as illustrated in **Figure 2**. As we describe in further detail below, supply from some resources may be limited by fuel inventories and the capacity of fuel systems. These limits include resource-level constraints due to limited fuel oil inventories and limited LNG contracts, and system-level constraints due to fixed natural gas pipeline transmission infrastructure.

Figure 2. Illustrative Resource Energy Supply Curve



Each resource's energy supply is offered at a price based on its marginal cost of supplying energy. The marginal cost of supply can reflect production costs and opportunity costs. Marginal production costs for fossil resources include costs for fuel, variable operations and maintenance ("O&M"), and emissions. These costs reflect resource-specific characteristics, including fuel type, heat rate, and emission rates.[21] Dual-fuel (gas/oil) resources are modeled such that units offer supply using the fuel with the lowest marginal cost, subject to constraints on fuel supply. The model does not consider unit-level permit requirements that may impose certain operational limitations, including limitations on the use of alternate fuels.[22]

Unit-specific production costs, heat rates, and emissions rates underlying units' offers are based on data from SNL Financial as of August 2019. Units not yet in service are assigned unit characteristics from similar, recently-built units. The model simplifies unit offers by assuming supply is offered in one block rather than multiple blocks. This assumption simplifies certain modeling complexities that are beyond the project's scope,

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21 For additional information on data sources, please see Section III.B. Emission costs for Massachusetts Global Warming Solutions Act compliance are $9.67 per metric ton based on the clearing price from the Regional Greenhouse Gas Initiative of New England and Mid-Atlantic States of the US (RGGI) 43rd auction held on March 13, 2019.

22 The model assumes that all resources with dual-fuel capability generate power using the fuel that allows generation at the lowest marginal cost. We do not account unit-specific environmental permit requirements that may limit the circumstances in which certain units with dual-fuel capability can operate on their alternate fuels.

but appear unlikely to meaningfully affect the analyses' estimates of ESI's impacts. The model accounts for certain unit operational limitations. Units that can supply DA energy options or real-time operating reserves through ramp capability can only provide such ancillary service supply when also supplying energy.

For resources with limited fuel inventory, particularly oil-fired resources, offers reflect both the resource's production costs and its opportunity costs. Because of these resources' limited fuel inventory, supplying energy in one hour may limit a resource's ability to supply energy in a different hour, in the same day or in a subsequent day. **Opportunity cost adders** allow a resource to account for this opportunity cost, and increase the likelihood that limited energy supply is used in the highest-priced hours. ISO-NE recently changed market mitigation procedures to provide automated calculation of opportunity costs that allow oil-only and dual-fuel resources to facilitate inclusion in their market offers.[23]

In our analysis, opportunity cost bid adders are calculated using a similar methodology to that incorporated into the opportunity cost models that ISO-NE makes available for market participant use. The adder reflects expected net revenue earned by a resource's "last" unit of energy over a three-day, multi-day horizon when hourly net revenues are sorted from highest to lowest. The net revenues of a resource's last unit of energy is calculated assuming that the resource only provides energy during the most profitable hours and that the resource has imperfect information about the fuel inventories of other resources and future energy prices. A resource only has an opportunity cost in situations where fuel is limited: if there is enough fuel to operate as expected for all profitable hours in the future time horizon at-issue, the resource has an opportunity cost of zero because it is assumed that using energy now will not preclude it from producing energy in the future.[24]

Imports are categorized as either price-responsive or non-price-responsive based on analysis of historical import offer patterns. Price-responsive imports are modeled using an offer curve calibrated against historical pricing, while non-price-responsive imports are modeled as a fixed quantity of imported energy in every hour.

Profiled resources are assumed to supply energy and ancillary services at levels consistent with historical supply patterns. For these resources, we rely on historical patterns because these resources would otherwise be particularly complex to model (e.g., pumped storage units) or their output is generally based on exogenous factors (e.g., solar and wind variable renewables).[25] For existing resources, we assume that each resource supplies energy and ancillary services consistent with its historical supply. For new resources (i.e., cleared in an FCA, but not yet operational) with a profiled technology, we assume supply is consistent with existing resources in the market. For variable renewable generation, including wind and solar generation, base year generation output is scaled to future levels consistent with new capacity that has cleared the FCA but is not yet operational. For example, given 2017-2018 historical total solar nameplate capacity of 941 MW and assumed future total solar nameplate capacity of 1,671 MW, the solar output for each hour is scaled up by

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23 Lowell, Jonathan, "Opportunity Costs and Energy Market Offers (Phase 1), ISO's Proposal to Estimate Opportunity Costs for Oil and Dual-Fuel Resources with Inter-temporal Production Limitations," October 9-10, 2018. https://www.iso-ne.com/static-assets/documents/2018/10/a7_presentation_opportunity_costs_and_energy_market_offers.pptx

24 For more information on the opportunity cost adder calculation, see the appendix.

25 The full set of profiled resources are: Battery Storage, Hydro - Pondage, Hydro - Run of River, Hydro - Weekly, Pumped Storage, Solar, Offshore Wind, and Onshore Wind.

77.5% (1,671 MW/941 MW = 1.775). Offshore wind generation profiles are based on historical wind buoy data from ISO-NE.

For profiled resources, we assume that each resource supplies GCR10 and GCR30 at levels consistent with historical supply of 10- and 30-minute real-time operating reserves. If the total quantity of historical cleared operating reserves exceeds the assumed GCR10 and GCR30 requirements (which occurs in some hours), the excess supply is used to satisfy other requirements introduced under ESI.

4. Day-Ahead Energy Option Offers

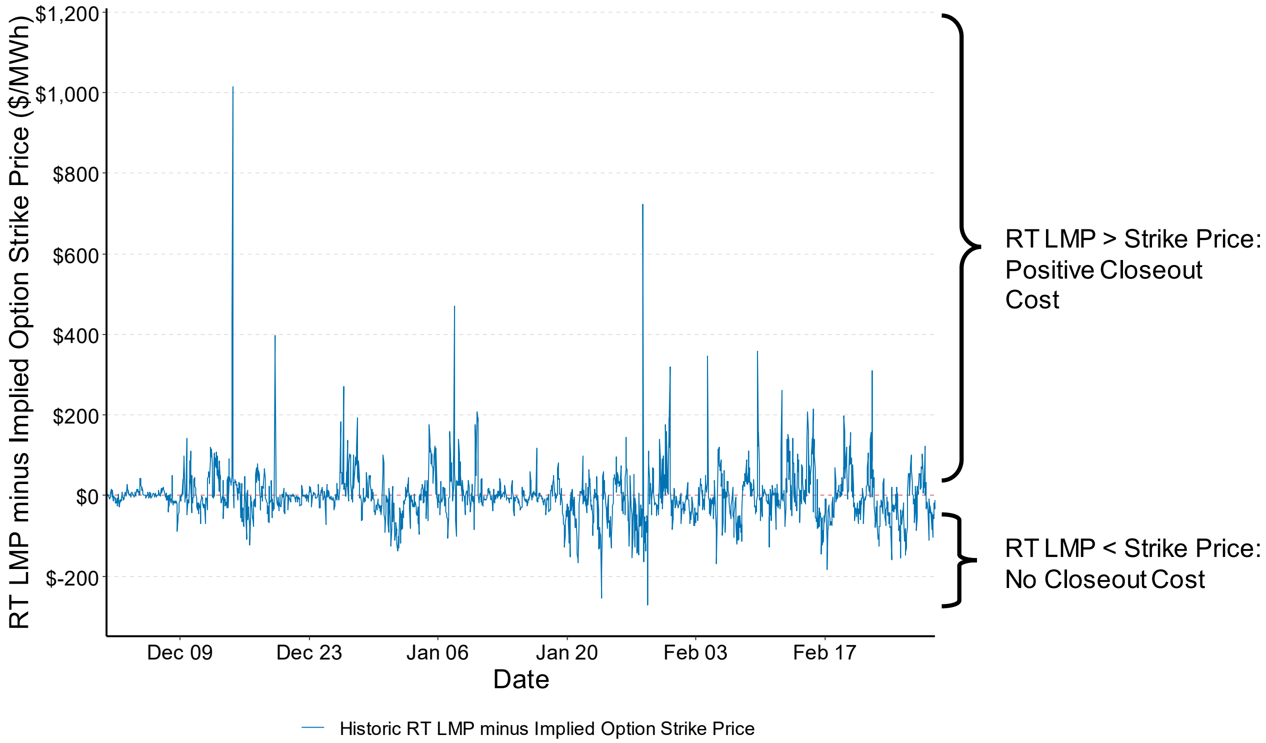
Under the ESI proposal, market participants submit offers to supply energy options into the day-ahead market. While the ESI proposal includes multiple day-ahead ancillary service products, the same underlying commodity – a DA energy option with the same strike price and that settles against the same real-time LMP ("RT LMP") – is used to satisfy each of the new GCR, RER, and EIR services. Thus, ***each resource submits an offer(s) for one commodity – the DA energy option – in each hour, even though the market participant may be able to supply multiple ESI products.***

While the financial settlement of each energy option product is equivalent, market-clearing prices for ESI products can differ if the optimization selects higher-priced option offers to satisfy the requirements for products with more-restrictive eligibility requirements. For example, the GCR10 price may be greater than the prices for other ESI products if resources meeting the more-restrictive 10-minute operational requirement offer options at a higher price. However, under ESI's pricing rules, a more flexible resource that is able to provide multiple ESI products is compensated at the rate that corresponds with the "highest quality" product it can provide.

We estimate supplier offers for DA energy options through a quantitative analysis based on historical market data. The estimated option offer prices reflect the basic financial tradeoff for suppliers if they are awarded a DA energy option. If they are awarded an option, they receive a fixed payment, reflecting the market-clearing price for the ESI product. In return, they agree to pay a settlement (or "closeout") cost, which is a function of the difference between the RT LMP in that hour and the strike price, which is set at a fixed value prior to submittal of option offer prices. When the RT LMPs are higher than the strike price, the option is "in the money" and suppliers must pay the difference between the RT LMP and the strike price. When this difference is zero or negative, the option is "out of the money" and the closeout cost is zero. Regardless of the closeout cost, option suppliers keep the fixed payment earned by writing the option.

Given uncertain RT LMPs, the seller receives a sure payment in exchange for an uncertain (potentially zero) closeout cost. This risky closeout cost is illustrated by **Figure 3**, which shows the difference between the RT LMP and the strike price on each day, where the strike price is set to the hourly historical DA LMP.

Figure 3. Difference between RT LMP and Implied Strike Price, and Corresponding Closeout Cost Winter 2013/14



Note: Strike price is modeled as the historical DA LMP.

Competitive offers for DA energy options will reflect suppliers' willingness to accept the obligation to settle ("close out") at the option's payout terms. In principle, this valuation reflects many factors, such as the expected payout, the risk associated with the option closeout, and the resulting financial risk faced by market participants, given a potential correlation between option settlement and other revenue streams.

To estimate offer prices for DA energy options, we assume that suppliers' willingness to sell the option reflects expected closeout costs plus a premium to capture the financial risk associated with the uncertain closeout costs. That is, in each hour:

$$DA\ energy\ option\ offer(h)\ = expected\ closeout\ cost(h) + risk\ premium\ (h)$$

This approach differs from the approach commonly taken to estimate the value of options traded in financial markets, which relies on constructing a portfolio (a "replicating portfolio") of financial products that replicates the returns for the option. The options procured through ESI, however, cannot be replicated through a portfolio of thickly traded assets (e.g., forwards and cash positions), as is the case for many options.[26] Thus, valuations

[26] The real options procured through the ESI proposal differ in many respects from financial options for thickly traded assets, such as stocks traded on major exchanges. The underlying asset for the DA energy options – RT energy – is not traded on any open

will reflect each market participant's expectations regarding likely costs and associated risks, potentially modified by opportunities to hedge such risks through other market products.[27]

The analysis (as well as the settlement of the DA energy options) is undertaken using historical RT LMP data rather than using an iterative process based on model output data. The use of historical data provides a robust approach to valuing DA energy options, as the option value is dependent on an actual distribution of real-time energy prices.[28] Future market conditions may differ from historical market conditions, but alternative approaches to estimating expected closeout costs, which are not grounded in historical data, would do no better in addressing such potential differences. Scenario analysis in which the model's assumed risk premiums are varied tests the sensitivity of this assumption on ESI's impacts.

When estimating option offers, the strike price varies by hour and is set at the historical DA LMP in each hour. In practice, of course, the ESI proposal envisions that the strike price will be set through different means, as the DA LMP will not be known when the day-ahead market is run. But for the purposes of our analysis, the historical DA LMP provides a reasonable estimate of the market's corresponding expectations for RT LMPs in each hour. In fact, this strike price would likely be more precise than any metrics available for use to set the strike price, as it is set within the day-ahead optimization rather than before it. **Figure 4** and **Figure 5** provides the distribution of all estimated offers and all cleared offers across all hours in the Frequent Case.

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exchange at present, making it impossible to "replicate" the option through a combination of cash purchases and forwards. Thus, the risk and financial properties of these options will differ from those of more liquid financial assets. To the extent that financial markets developed new products or expanded trading in existing illiquid products, potentially in response to ESI, the methods for pricing options and mitigating option risks could evolve.

27 Cochrane, John and Jesus Saa-Requejo, 1999, "Beyond Arbitrage: Good-Deal Asset Price Bounds in Incomplete Markets."

28 Among available options, the use of historical data is the most robust approach to estimating this distribution, as other approaches would require parametric assumptions without an empirical foundation. **Section III.D.2** provides further detail on, and rationale for, the use of historical RT LMPs for settlement of DA energy options.

Figure 4. DA Energy Option Offer Prices, All Market Offers, Winter Frequent Case

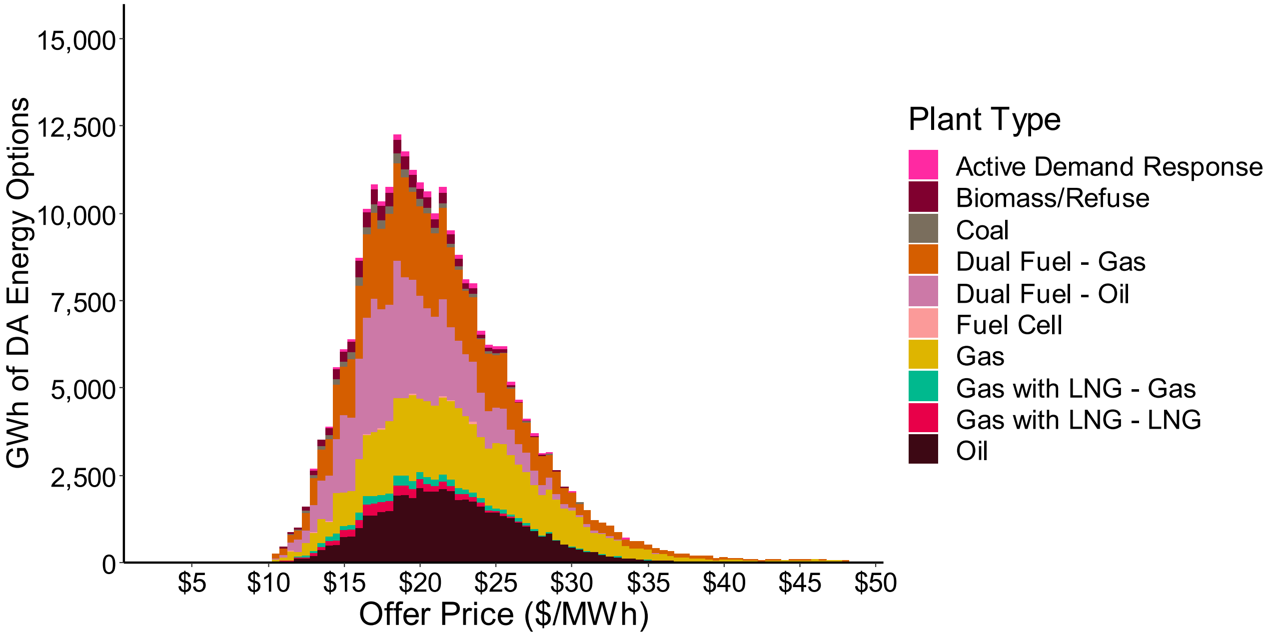
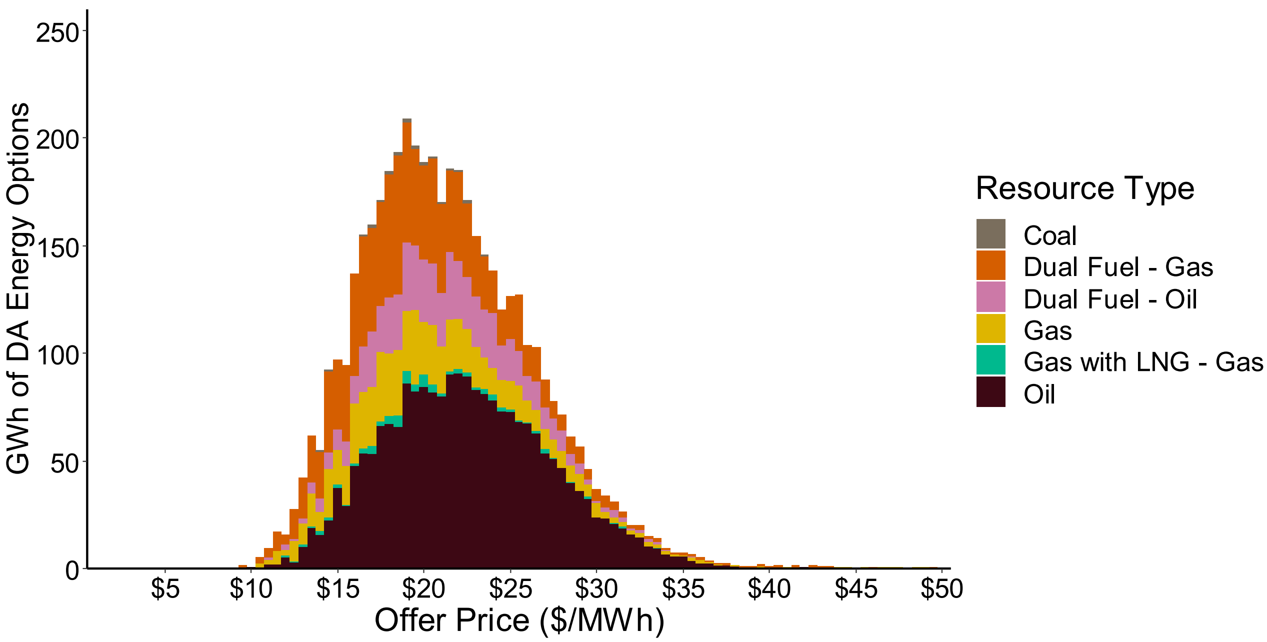


Figure 5. DA Energy Option Offer Prices, Cleared Offers, Winter Frequent Case



Below, we briefly describe our methodology for estimating the offer prices for DA energy options. In the appendix, we describe our methodology in greater detail.

a) Expected Closeout Costs

Expected closeout costs are estimated through a simulation process drawing on historical data from recent winters (2012 to 2018). This simulation process is used to estimate the distribution of RT LMPs (relative to the strike price) in each hour, and then to estimate the expected closeout cost of the option conditional on that distribution. Because the closeout costs of the DA energy option have an asymmetric structure, with positive costs if the RT LMP exceeds the strike price and no cost otherwise, it is necessary to evaluate this distribution to ensure that the expected cost is not understated.

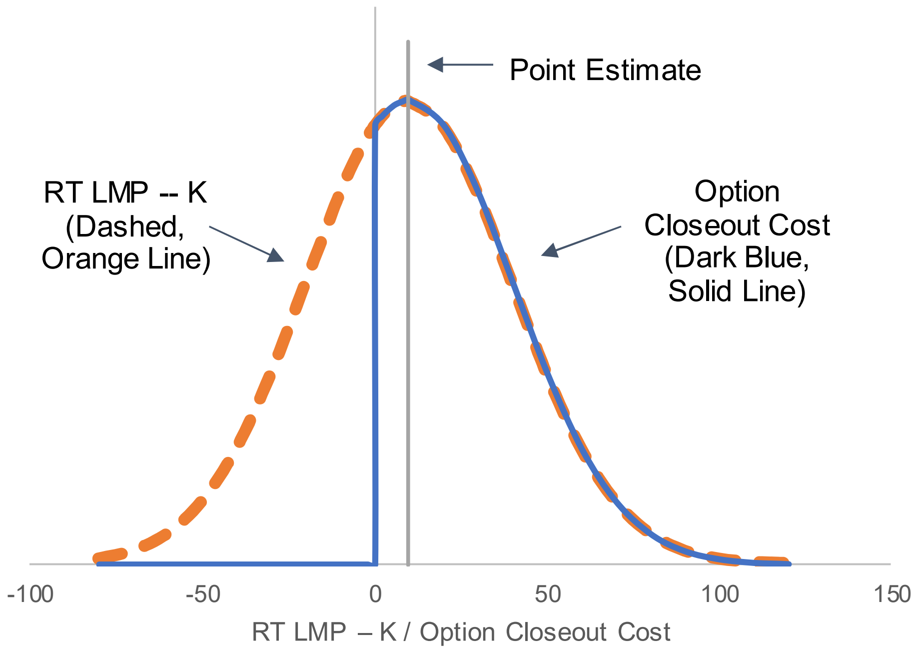
Expected closeout costs are assumed to be uniform across all market participants. While, in reality, there may be differences in market participants' expectations regarding RT LMPs, the challenges associated with estimating these differences in a reasonable manner for each supplier in each hour across all potential market conditions would be significant. Thus, all heterogeneity in DA energy option offers is due to the risk premiums, which differ across resources.

Expected closeout costs are estimated in several steps. First, we develop a single "point estimate" for the difference between the RT LMP and the strike price (i.e., *RT LMP – K*) given hour-specific market and weather conditions. This point estimate is created by estimating a linear regression model for *RT LMP – K* as a function of several variables, including temperature, rolling historical volatility in closeout costs, and various date fixed effects, and then using this model to estimate a single fitted value for each hour based on its observable characteristics.[29] Including these variables in the regression controls for information that would be available to suppliers when forming expectations about closeout costs in order to develop an option offer price in the day-ahead market.

The second step accounts for the statistical uncertainty in our single point estimate. Accounting for uncertainty in the potential values for *RT LMP – K* ensures that expected closeout costs are not understated. **Figure 6** illustrates this effect for a distribution of values of *RT LMP – K*. Because closeout costs are asymmetric, the closeout costs associated with a distribution of values of *RT LMP – K* (the dashed orange line) are equal to zero when *RT LMP – K* is negative. Thus, the average closeout cost estimated over the full distribution is greater than the point estimate, because it accounts for the closeout costs asymmetric distribution. The Monte Carlo simulations we use to estimate the probability distribution illustrated in **Figure 6** are described in greater detail in the appendix.

[29] The model is fit using data from winter months from December 2012 through February 2018. For the non-winter cases, the same model is fit to data from each of the nine-month periods that comprise the non-winter seasons.

Figure 6. Illustration of Distribution of DA Energy Option Closeout Costs



b) Risk Premium

Our estimates for risk premiums build off risk preferences revealed in the market. In particular, we assume that the risk premiums for taking forward positions in DA energy markets provide information about market participants' willingness to take on a potentially risky forward position. The estimated risk premium component of the DA energy option offer reflects estimates of these forward risk premiums, with adjustments made to account for differences in the respective financial positions (e.g., the relative prices and the relative magnitude of the financial risk). **Figure 7** and **Figure 8** provide the estimated risk premiums for all hourly DA energy option offers and cleared DA energy option offers for the Frequent Case, where ESI is assumed to be in effect. Further details on the methodology we used to estimate the risk premiums is provided in the appendix.

Figure 7. DA Energy Option Risk Premiums, All Market Offers, Winter Frequent Case

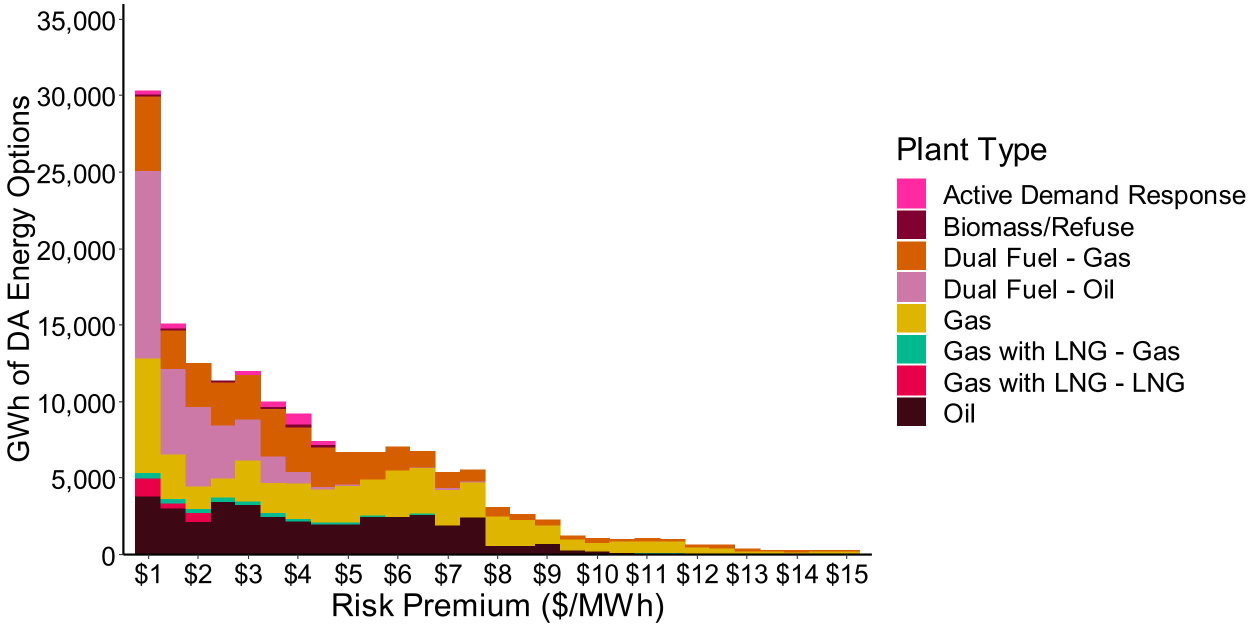
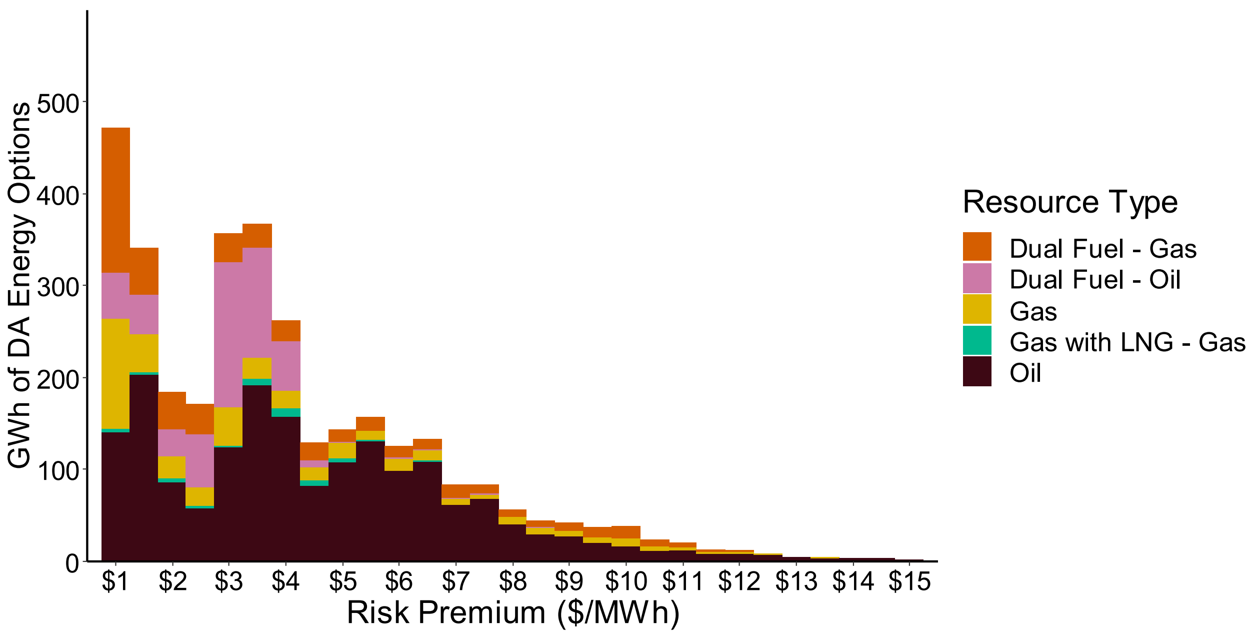


Figure 8. DA Energy Option Risk Premiums, Cleared Offers, Winter Frequent Case

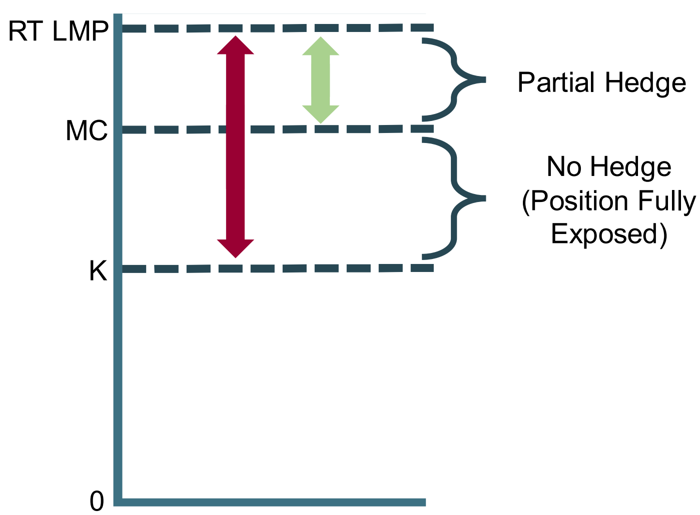


Like any financial option, financial risk is greatest when the underlying commodity prices (in this case, RT LMPs) are more volatile. With higher volatility, there is a greater risk of large closeout costs that can have a variety of follow-on corporate implications (impacts to cash flow, credit ratings, etc.). Thus, we assume that the risk premium is greater under system conditions in which higher levels of RT LMP volatility are expected. However, the impact of a DA energy option award on a supplier's financial risk will depend not only on the magnitude of this risk but also on other market net revenues earned by the supplier and the extent to which these revenues are correlated with the DA energy option's closeout costs.

For valuing the risks associated with selling energy options, an important factor to consider is that closeout costs and supplier revenues in the real-time energy markets will often be negatively correlated. When RT LMPs exceed the strike price, set roughly at the corresponding DA LMP for that hour, this signals that energy is likely needed from resources that did not clear for energy in the day-ahead market. Thus, while suppliers of DA energy options face positive closeout costs when RT LMPs exceed the strike price, they are also more likely to provide energy in real-time and receive incremental real-time energy revenues during these hours. As a result, the resource's ability to provide energy to the system in real-time serves as a hedge for the sale of a DA energy option, as the real-time energy ("RT energy") revenues associated with high RT LMPs may offset the closeout costs during such periods.

The hedge provided by physical energy inventory is greatest when this inventory can be supplied to the market at a lower marginal cost. This point is illustrated by **Figure 9**. Assume that the strike price is *K* and that the DA energy option settles at *RT LMP*. In this case, the closeout cost faced by someone holding a DA energy option is represented by the red arrow. Suppose, however, that this resource can supply RT energy to the market at marginal cost of *MC*. In this case, on a per MWh basis, the option holder earns *RT LMP – MC* in net energy revenues (equal to the energy market revenues it is paid for providing this energy, less the marginal costs of producing it), while paying out *RT LMP – K* in closeout costs. The net result is a smaller net loss of *MC – K* compared to the closeout cost alone (and where this loss does not account for the initial day-ahead payment for selling the option). Thus, the physical energy inventory provides a partial hedge to the DA energy option's risks.

Figure 9. Illustration of Physical Hedge Provided by Energy Inventory to DA Energy Option Risk



As the above example illustrates, the extent to which physical energy inventory hedges the risks of a DA energy option depends on the marginal costs at which that inventory can be supplied. When the marginal costs are low relative to the strike price (e.g., when MC is equal to K), the inventory provides a more effective hedge, whereas when the marginal costs are high relative to the strike price, the inventory provides a more limited hedge. As a result, the financial risks of a DA energy option depend on the resource's marginal costs, given the potential for this energy supply to offset closeout costs when RT LMPs are higher. Thus, we account for the resource's cost of energy supply when calculating risk premiums.

The potential for physical energy inventory to mitigate the financial risk of a DA energy option depends not only on the marginal costs of this supply, but also on operational and intertemporal factors that may limit a resource's ability to supply energy in real-time in response to higher-than-expected RT LMPs. We account for certain operational and intertemporal factors when calculating the risk premium. These factors include:

- ***Performance Risk.*** For all resources, there is the risk that the resource is unable to provide energy during periods of high RT LMPs due to a forced outage or other operational factors (e.g., transmission outage).
- ***Lead Time and Intertemporal Factors.*** Lead times required for a resource to become fully energized and other intertemporal factors may limit a resource's ability to hedge closeout cost risk if these factors limit its ability to deliver energy supply during periods of high RT LMPs to cover the real-time settlement cost of a DA energy option. Similarly, some resources' supply may be limited by inter-temporal factors, as reflected by offer parameters such as minimum run-time and minimum down time.
- ***Fuel Cost Risk.*** Natural gas-only resources face fuel price risk because prices may be higher in the intra-day natural gas markets compared to the day-ahead natural gas market, especially during periods when the RT LMP exceeds the DA LMP, and when trading in supply for delivery to a particular resource may be illiquid.
- ***Start-up Cost.*** Offline resources may incur start-up costs in addition to short-run marginal costs for physical energy supply to cover a DA energy option settlement. This factor considers this incremental cost via an additional risk factor.

These parameters vary across technologies, depending on technology-specific attributes. **Table 5** shows how these factors vary across electricity generation technologies, with more detail provided in the appendix. In the table, a check mark indicates that the category is modeled for the given technology, and the risk premium is increased accordingly. A check with a "+" symbol indicates that the levels modeled are greater, relative to those with just a check.

Table 5. Operational and Intertemporal Factors Accounted for in Estimated Risk Premium

	Operational and Intertemporal Factors (*p*)		Cost Factors (*m*)	
	Performance Risk	Lead Time	Fuel Cost Risk	Start-up Cost
Combustion Turbines				
Gas-only			✓+	✓+
Oil-only, Dual Fuel			✓	✓+
Combined Cycle				
Gas-only	✓	✓	✓	✓
Oil-only, Dual Fuel, LNG Contract	✓	✓		✓
Steam				
Oil-only, Dual Fuel	✓+	✓+		✓

5. *FER Requirement and Payments*

The FER constraint ensures that there are sufficient DA energy awards and options available to meet forecast energy in each interval. With other ESI products (RER and GCR), the quantity procured is largely independent of the quantity of energy procured, as these quantities are set to meet contingencies. However, with EIR, the market clearing algorithm (endogenously) *solves for both the quantity of EIR and the quantity of cleared DA energy*. Specifically, the FER constraint, satisfied through EIR, has the following structure:

EIR = maximum (0, forecast load – cleared physical DA energy supply)

By virtue of this structure, so long as cleared DA physical energy is less than forecast load, additional DA energy supply leads to a direct ("1-for-1") reduction in the quantity of EIR that needs to be procured to ensure that there is energy in real-time to meet the forecast load.

For example, assume that for a given hour, the forecast load is 110 MWh and the cleared physical DA energy is 100 MW. In this case, the EIR is 10 MWh, equal to the difference between the forecast load and cleared physical DA energy. Consider the impact of a 1 MWh increase in cleared DA physical energy from 100 MWh to 101 MWh. With the 1 MWh increase in energy, the total cost of procuring DA energy increases. But, the 1 MWh increase in DA energy reduces EIR by 1 MWh to 9 MWh:

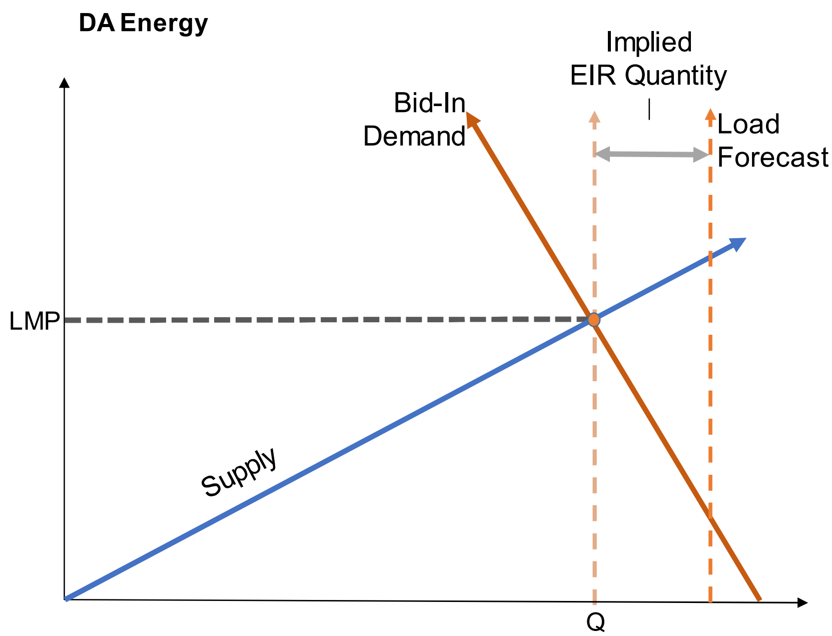
EIR = maximum (0, 110 MWh – (100 MWh + 1 MWh)) = 9 MWh

Thus, if the day-ahead optimization clears 1 MWh of additional physical energy, it will reduce the quantity of EIR by 1 MWh.

When determining the optimal quantity of DA energy and EIR, the optimization accounts for this interaction between the cleared physical DA energy and EIR, which is an inherent element of the ESI design. As a result, when determining the quantity of DA energy that clears the market, the clearing algorithm accounts for the cost sellers incur by providing additional DA energy, the benefit that energy provides to buyers, and the savings associated with a potential reduction in quantity of EIR that is procured.

Under current market rules the day-ahead market does not procure EIR to offset any difference between forecast load and physical energy supplied, and any such costs that would be associated with a shortage are therefore not considered. As such, the DA energy market generally clears at a price and quantity where the supply offer curve and bid-in demand curve intersect. As shown in **Figure 10**, the resulting outcomes can lead to a gap between the quantity of physical energy that clears the market and the load forecast. In **Figure 10**, this gap is represented by the "Implied EIR Quantity".

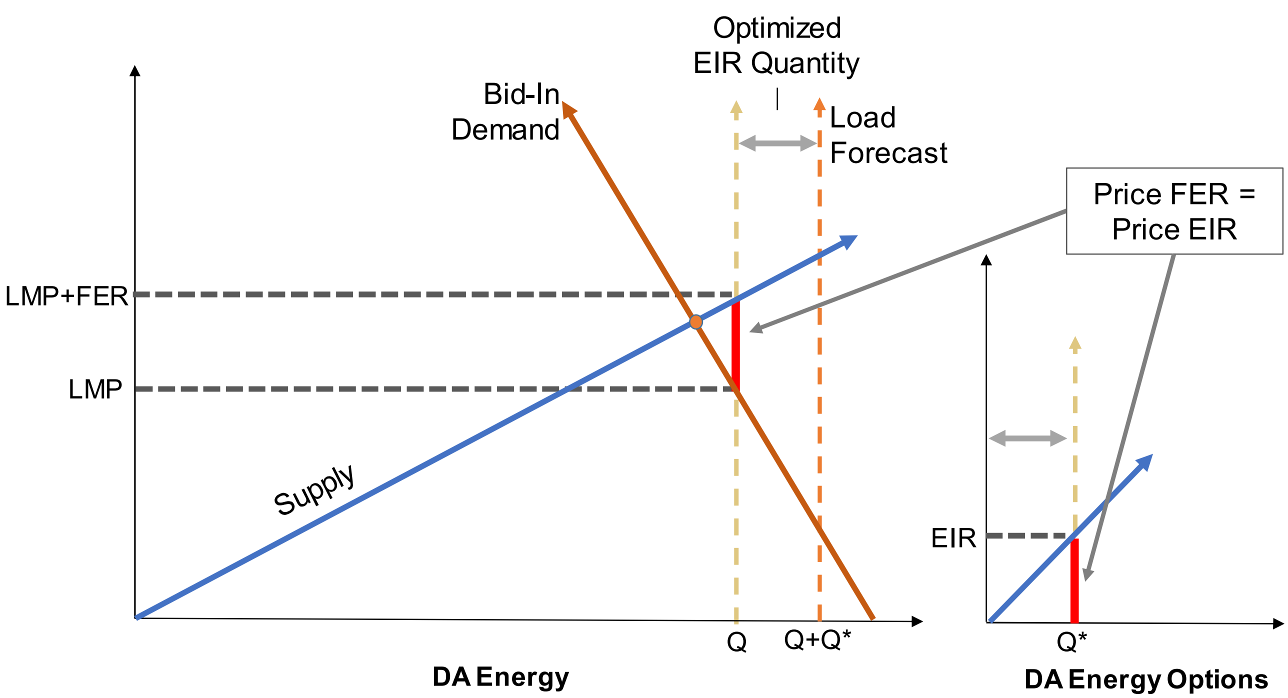
Figure 10. Illustration of the Implied EIR Quantity Under Current Market Rules



Under the ESI proposal, the market-clearing algorithm determines the optimal (least cost) quantity of DA cleared energy and EIR by balancing (on the margin) the loss from additional MW of DA energy with the cost of additional DA EIR energy option MWh. In this tradeoff, the optimization calculates the welfare "loss" of additional DA energy as the *difference* between the social cost of supplying power for energy, reflected by supply offer prices, and customers' demand for power, reflected by demand bid prices for energy. At the intersection of supply and demand (price "LMP" in **Figure 10**), this loss is zero because the cost to supplying this increment is equal to the benefit that demand derives from procuring it. However, once the FER, and the procurement of EIR to satisfy this requirement, is considered under the ESI design, social welfare may not be maximized at this point. In particular, if the market clears the same quantity of DA energy as under current market rules, a large quantity of EIR would be required to meet the load forecast, which could be costly as the market would procure DA energy options to make up this EIR gap.

Figure 11 illustrates the market outcome after co-optimization of DA energy and EIR under ESI. With the co-optimization of DA energy and EIR, total social surplus is maximized by increasing the quantity of DA energy procured, which in turn decreases the EIR quantity, until the marginal loss from procuring DA energy equals the cost of DA energy options, on the margin. In **Figure 11**, the marginal loss from procuring DA energy is reflected by the difference between the Supply and Bid-In Demand curves at the market clearing quantity of energy, *Q*, represented by the red vertical line. Physical generators supplying DA energy are paid a total price of LMP+FER, the cost of the marginal energy supply offer. In addition, a quantity of EIR (*Q**) clears to ensure that the sum of *Q* and *Q** equals the load forecast. The quantity of DA energy and the price paid for this energy increase compared to the market-clearing quantity and price under current market rules.

Figure 11. Illustration of Interaction between DA Energy and EIR under ESI



Consistent with the ESI market design, the model solves for both the quantity of DA energy and the quantity of EIR while accounting for this interaction between the DA products. Thus, the analysis provides estimates for the increases in cleared DA physical energy supplies that are expected under ESI due to this co-optimization, which will reduce the gap between cleared DA physical energy supplies and the ISO-NE load forecast, relative to current market rules.

Our analysis also accounts for expected market responses to these shifts in cleared DA energy supply due to ESI co-optimization of ESI products, including these EIR interactions. In particular, the model accounts for adjustments to bid-in demand that would be expected in response to the reduction in DA LMP, illustrated by comparison of **Figure 10** and **Figure 11.** Because there has been no change in the underlying expected RT LMP under ESI, if the model did not include such an adjustment, there would be a persistent and predictable difference between DA and RT LMPs that could offer a profitable trading (arbitrage) opportunity where participants buy at the (lower) DA LMP and then sell at the (higher) RT LMP. Faced with such an opportunity to earn positive profits, market participants will increase their bid-in demand for DA energy until their trading activity has competed away these expected profits. To account for this trading activity, we adjust (increase) bid-in demand so that the resulting DA LMPs remain generally consistent with the expected RT LMPs. As a result, DA LMPs remain roughly in-line with *expected* RT LMPs, while DA LMPs and RT LMPs vary from day-to-day given the usual idiosyncratic variation in weather, loads and other factors between day-ahead and real-time markets.

6. Real-Time Markets

The real-time energy market functions similarly to the day-ahead market described above. Resources offer into the real-time energy market based on their marginal and opportunity costs. The market clears to ensure that demand is met, supply and demand are balanced, and real-time operating reserve constraints are met, while co-optimizing the procurement of energy and operating reserves. The model includes a single 10-Minute Reserve product that combines spinning and non-spinning reserves and 30-Minute Operating Reserves product. Consistent with current market rules (which ISO-NE is not proposing to change with ESI), resources do not provide bids for these reserve products; instead, reserves are co-optimized to minimize energy offer costs based on the Claim10 and Claim30 capabilities of off-line resources (or ramp capabilities for on-line resources). Consistent with their GCR counterparts, the requirements in each hour for TMR and TMOR are assumed to be fixed at 1,600 MW and 2,400 MW, respectively, and quantities of MW provided toward TMR cascade into the TMOR requirements. Reserve Constraint Penalty Factors are set at $1,500 (for TMR) and $1,000 (for TMOR).

As is generally consistent with actual market operations, the RT energy market clears at inelastic (fixed) load levels, and does not reflect the clearing of supply offers and demand bids, as is the case in the day-ahead market. The model's realized RT load levels differ from both its cleared DA energy demand and the forecast load, reflecting normal daily variation and market uncertainty. We do not model differences in resource availability between day-ahead and real-time markets, although several scenarios explore the impact of shocks to resource availability due to sudden unexpected outage contingencies.

C. Fuel Inventory Constraints

Fuel availability has a significant impact on the energy supplies that certain types of fossil-fuel resources can deliver in real-time during winter months. The model accounts for both natural gas system delivery constraints and resource-specific fuel oil constraints. As described earlier, offer prices from fuel-oil resources with limited fuel supplies reflect these constraints through the opportunity cost adders that support the delivery of this energy when it is most valuable. In addition, the model assumes that resources do not supply energy and/or ancillary services in the day-ahead or real-time markets if these positions cannot be supported by physical inventory available at the start of the day. While these fuel constraints are modeled in both the winter and non-winter months, given the lower level of LDC natural gas demand these constraints generally have no material impact on market outcomes during non-winter months.

1. Natural Gas Market Assumptions

Natural gas is used extensively for residential and commercial heating in New England during the winter and is drawn off interstate gas pipelines for residential distribution by LDCs. Gas-fired power plants draw their fuel supply off the same interstate pipelines but generally have interruptible (i.e., less firm) contracts with fuel suppliers. As a result, during cold winter days when demand for natural gas to use in heating is high, less natural gas is available for use by electrical generators. In the model, the natural gas available for electrical generation in any given hour is calculated as the total potential injections into the system from the interstate pipeline system and LNG terminal supplies less the demand for natural gas from LDCs:[30]

Natural Gas Available for Generators

≤ Interstate Pipeline Capacity + LNG Terminal Supply – Net LDC Gas Demand

Our gas availability analysis is based on natural gas pipeline capacity and LDC demand (by temperature) data and models provided by ISO-NE, and is consistent with the fuel security review of Forward Capacity Market de-list bids performed by ISO-NE for FCA 14 (the FCA 14 Fuel Security Review).[31] Pipeline capacity into ISO-NE is assumed to total 3.59 Bcf per day, which includes capacity for Algonquin, Iroquois, Tennessee, and Portland. This pipeline capacity takes into account capacity expansions expected to be completed by 2025 and subtracts gas under "pass-through" contracts that flow to Long Island. LDC demand by temperature is modeled using the ICF model from the FCA 14 Fuel Security Review. LDC demand increases, and gas available for electric generation drops, when the ISO-NE hub temperature falls.[32] Thus, based on the historic 2016/17 winter when temperatures were generally mild, more natural gas is available for electric generation in the Infrequent Case than in the Frequent Case, which uses the historic 2013/14 winter when winter temperatures tended to be lower.

In the Central Cases, we assume that the region's available LNG supply is consistent with (1) the estimated delivery capability of the Canaport LNG facility to New England, and (2) the exit of the Everett Marine Terminal LNG facility in Everett, MA (commonly referred to as Distrigas or DOMAC.[33] This assumption may either under- or overstate the likely supply of LNG under Central Case conditions. While potential supply from Canaport may not be fully contracted at present, the assumed exit of DOMAC would likely increase demand for natural gas from remaining sources of fuel supply.

Figure 12 shows the natural gas supply available to the electricity sector at various temperatures after accounting for these supplies and uses**.** This available supply reflects the difference between the maximum available natural gas supply, represented by the shaded area, and LDC gas demand, represented by the black line. As the temperature gets colder (moving to the right on the figure), the LDC natural gas demand increases, leaving a decreasing quantity of gas supply for the electric sector.

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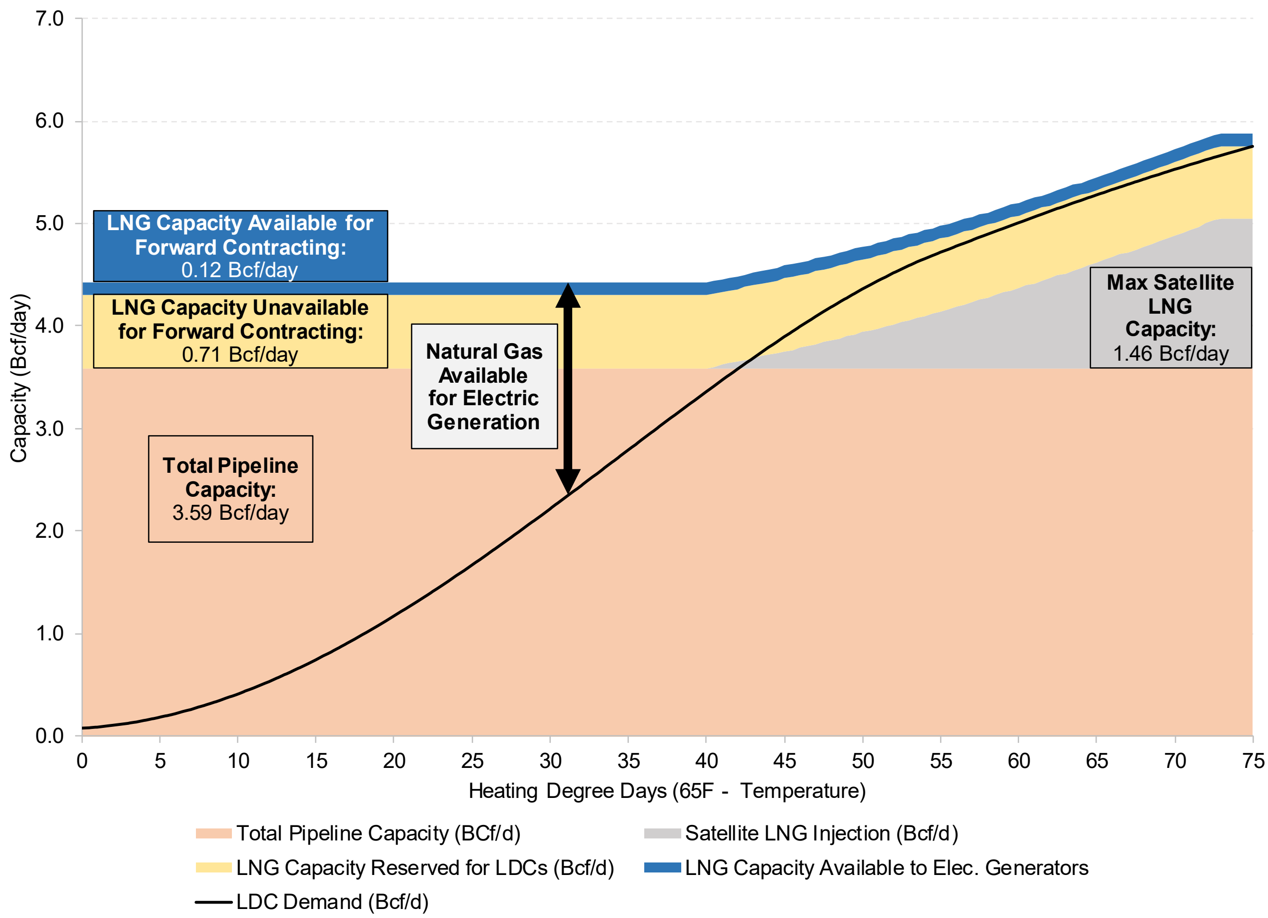
30 Natural gas available for generation is "shaped" across the hours of a day to allow for greater gas use during hours of peak electrical demand. No geographic constraints are modeled.

31 Sproehnle, Norman, "Forward Capacity Auction 14 (FCA 14): Fuel Security Review Inputs Development," March 29, 2019.

32 LDC demand for pipeline gas is also (partially) offset by injections of gas supply from satellite LNG facilities during periods of extreme cold when demand is highest. These satellite facilities are typically owned and operated by the LDCs.

33 Deliverable LNG supplies from Canaport are transported to New England via the Maritimes and Northeast Pipeline.

Figure 12. Natural Gas Supply and Demand by Heating Degree Day



In response to the increased incentives for delivery of energy in real-time created by ESI, we assume that certain gas-only generation units enter into forward contracts with an LNG terminal in the ESI cases. Under these forward contracts, the contract holder pays an up-front reservation charge in exchange for the right to purchase natural gas at an agreed-upon commodity price, assumed to be $10 per MMBtu, on 10 days over the course of the winter. These contracts do not increase the aggregate supply of natural gas available to the electricity sector, as we assume that the LNG terminals supply fuel to the market at their full transmittable capacity even if no such contracts are signed.[34] However, the forward LNG contracts may reduce the cost at which fuel is procured, and may lower the cost of power supply for resources with these contracts. To the extent that ESI would incent contracts with LNG terminals for supplies that would otherwise not be brought to the region, the Impact Assessment would tend to understate the reliability benefits of ESI.

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[34] The structure of this contract does not have a material effect on outcomes of the Impact Assessment. The assumed commodity price ($10 per MMBtu) for the contract is most consistent with a call option contract, in which the contract holder has the right, but not the obligation, to take supplies. If a take-or-pay contract were assumed, the commodity cost would likely be lower, which could lower production costs during some hours, but would otherwise generally leave market outcomes unchanged.

Daily natural gas prices in each case are the unadjusted historical base year prices for Algonquin natural gas for the given day (where the historic day-ahead price is assumed for both day-ahead and real-time), and are used in conjunction with unit heat rates to determine fuel costs for natural gas and dual fuel units. Our natural gas market analysis does not attempt to calculate a general equilibrium natural gas price and quantity for each day. Such modeling is beyond the scope of our assignment, and would be particularly complex, given the region's unique natural gas demand and supply conditions.

2. Liquid Fuel Price, Storage, and Refill Assumptions

The energy supply that can be produced by oil-only and dual-fuel units running on oil is constrained by the amount of fuel oil that is in their storage tanks at the beginning of each hour. The model maintains an accounting of fuel in inventory (storage tanks) for each unit given its initial inventory, subsequent use to generate power, and replenishment of inventory ("refueling"). Inventory levels are updated for each operating day.

Each oil-only or dual-fuel unit starts the winter (or other modeling period) with an initial inventory that is drawn down if the unit generates electricity (using oil). If the inventory falls below a unit-specific "trigger quantity," then the unit receives a replenishment shipment of liquid fuel (equivalent to a number of tanker truck or fuel barge loads) after a specified order lead time. Unit replenishment behavior is assumed to differ across units based on the means of replenishment (tanker or barge), maximum tank size, and other characteristics. **Figure 13** shows an illustrative example of the fuel inventory of a specific resource on each day, and the various parameters that affect refueling over the course of the winter.

Figure 13. Illustrative Daily Fuel Inventory with Refueling Model Parameters

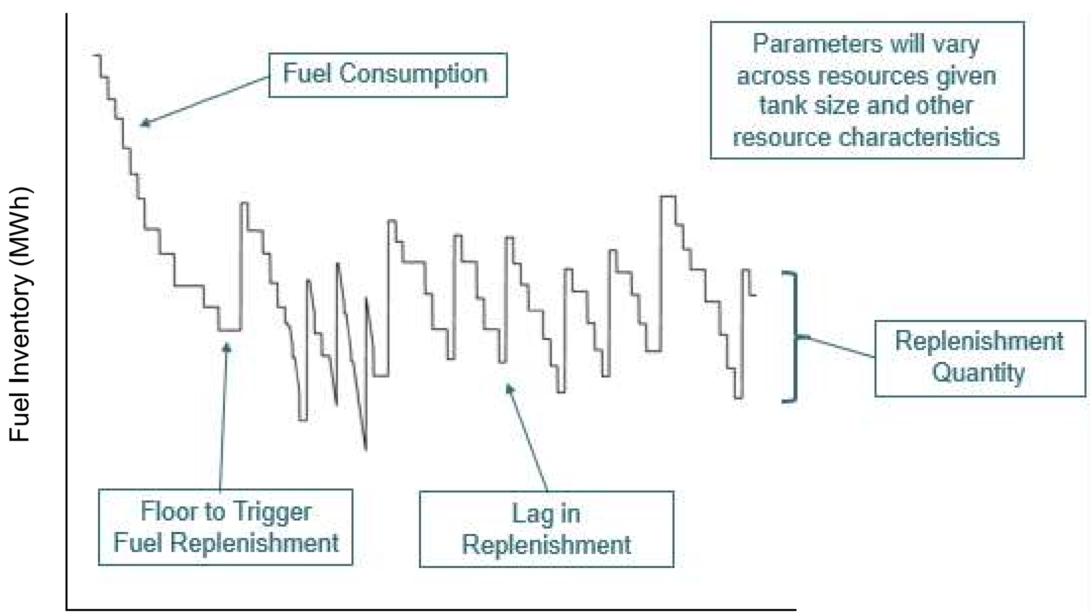


Table 6 summarizes the parameters used in each unit's refueling model. These parameter estimates are based on a combination of sources, including the ISO-NE fuel surveys, discussions with system operators and other New England market participants, and experience with fuel security analysis in other regions.

Table 6. Fuel Oil Resources, Initial Inventory and Refueling Model Parameters

Refuel Type		Truck			Barge
Size		**Small**	**Medium**	**Large**	
Unit Tank Storage Capacity (days)		(0 - 1]	(1 - 3]	(3 +)	(0 +)
Initial Fuel Inventory	CMR	December 2018 Inventory			
	ESI	CMR Fuel Levels + Incremental Inventory			
Rate of Fuel Delivery (gals per day)	CMR	123,750	123,750	123,750	375,000
	ESI	165,000	165,000	165,000	500,000
Last Refill Date		2/28/2026	2/28/2026	2/28/2026	2/14/2026
Order Lead Time (days)		1	1	1	4
Refill Threshold (percentage of initial inventory)		70%	40%	30%	10%

Note: Rates of fuel delivery are based on delivery capability and shipment quantity.

The maximum fuel oil storage capacity for oil and dual fuel units is based on historical unit-specific fuel survey data from ISO-NE. Units are assumed to enter the winter modeling period with a winter starting fuel quantity that is a fraction of their maximum fuel storage capacity, also based on historical fuel survey data.[35] Under CMR, each unit's starting inventory is based on its December 2018 inventory, when the Winter Fuel Program was not in effect.

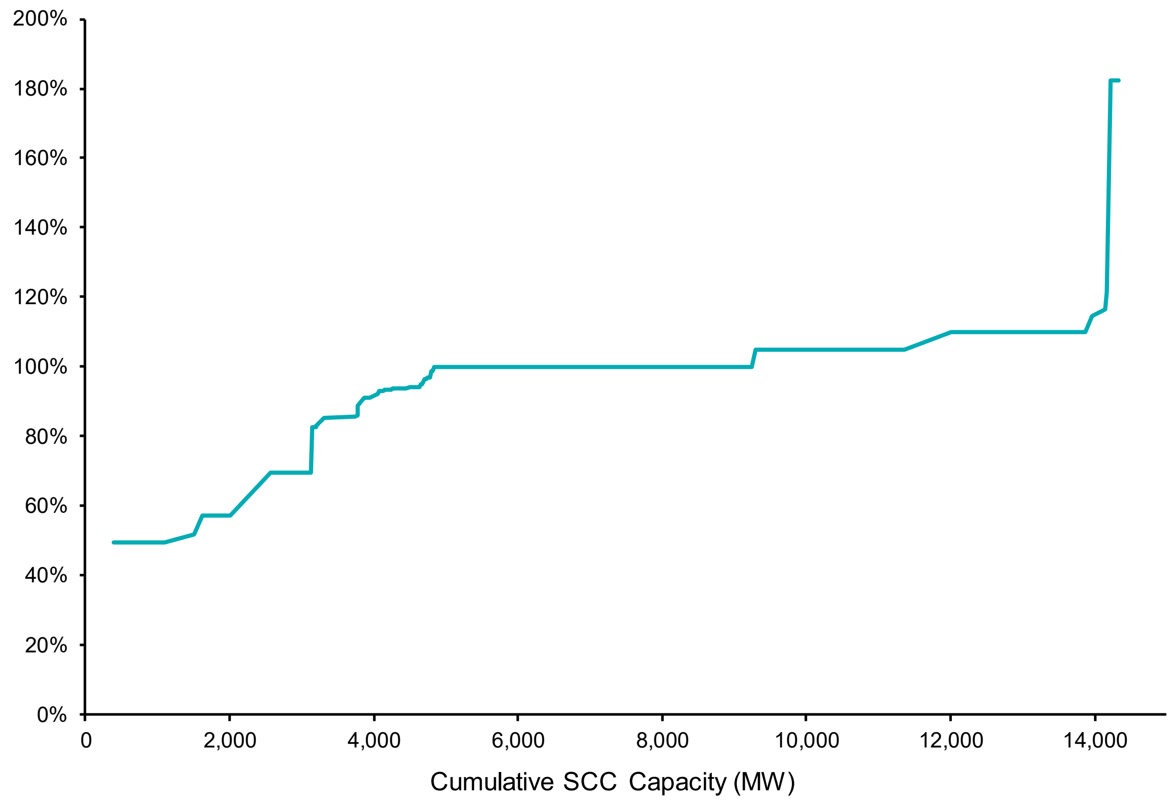
The incentives created by the ESI proposal are expected to change these fuel inventory and refueling decisions. Under ESI, we assume the units start the winter with a larger initial inventory than in the CMR Case. Initial inventories under ESI are set using information on December inventory levels from years when ISO-NE's Winter Program was in effect (winters of 2014 to 2017). These programs compensated resources for increasing stored fuel supplies, with compensation mechanisms differing across the years the programs were in effect. Thus, the initial inventories held during these winters reflect the market's response to the incentives created by the earlier winter programs, and are a reasonable starting point for an expected response to ESI.

Using the average December inventory as a starting point for calculating assumed initial fuel inventories under ESI, we make subsequent adjustments (above or below the 2014-17 Winter Program levels) to account for a number of factors. In particular: units with low marginal generation costs are assumed to hold more fuel (relative to other units), as these resources are more competitive at supplying DA energy and DA energy options; certain units with very large storage tanks (relative to capacity) are assumed to hold less fuel than was held during the Winter Program periods, as less market benefit was observed from incremental inventory; and some units with small tanks (relative to capacity) are assumed to hold more fuel, when historical December inventories were relatively low. In **Section IV.1**, we evaluate whether the assumption about this increase in starting inventories appears to be consistent with the incremental incentives to maintain energy inventories that ESI creates. **Figure 14** illustrates this variation in initial inventory, showing the distribution of the ratio of

35 Units with storage enter the modeling period with as much liquid fuel as they held during winters of 2016/17 and 2017/18, when the ISO-NE Winter Fuel Program was in effect.

(1) assumed initial inventory under ESI to (2) the average Winter Program initial inventories (December 2014 to 2017) across the set of resources in the analysis that can hold fuel oil in the analysis.

Figure 14. Initial Fuel Oil Inventory under ESI
Assumed Initial ESI Inventory Relative to 2014-17 Average December Storage



Within the model, fuel inventories start at the initial level and are reduced as the resource consumes fuel to supply electricity in real-time. Fuel inventories are drawn down until fuel stock declines below a unit-specific refueling threshold that is set as a fixed fraction of initial inventory. When inventories fall below this threshold, refueling occurs. Both the refueling threshold and the refill rate – i.e., the quantity of liquid fuel (per day) – depend on how the resource is refueled (tanker or barge) and the size of the unit's fuel tank. For example, as illustrated in **Table 6**, units that refuel by barge will refuel less frequently but with a larger quantity per refill compared to units that refuel by truck. In all cases, units will never refuel to a level greater than their initial inventory.

Along with the changes to initial inventory levels discussed above, we also assume changes to the refueling strategies used by market participants in response to ESI's incentives for increased energy inventories. In particular, we assume that under ESI, fuel-oil resources refuel at a faster rate (i.e., more fuel per day), one-third higher than in the CMR case. This assumption is designed to reflect the potential responses of market participants to the incentives created by ESI.[36]

Assumed fuel oil prices are the unadjusted monthly Chicago Mercantile Exchange futures contract prices as of August 2019 for delivery months as far into the future as possible. If a unit is modeled to run on liquid fuel in a given hour, fuel costs are based on fuel replacement cost at the time it is burned, not the original purchase price of the fuel.

D. Market Settlement & Model Outputs

The model determines production of electricity in each hour, day-ahead and real-time energy and ancillary service prices, quantities of day-ahead and real-time products supplied by each resource, and various resource- and system-level variables related to energy inventory and aggregate fuel use. These outputs are used to develop summary metrics for each case and scenario, including market price and payment impacts, energy mix, and fuel system operational metrics. These outcomes reflect the two-part settlement process used in the New England markets. ESI's impacts on outcomes are then calculated by taking differences in outputs between CMR and ESI cases.

1. Market Price Impacts

Hourly market clearing prices (e.g., LMPs in the energy market) are simulated for the day-ahead and real-time markets. Differences between DA and RT LMPs reflect many potential factors, including: incremental energy inventory procured under ESI that is used to meet DA and RT energy demand; substitution in resource-level awards under ESI between energy and DA energy options; and/or changes in opportunity costs given fluctuations in resource-level energy inventory.

Hourly clearing prices for energy market products are set using the same approach as the current (and proposed) market algorithms. For DA energy, RT energy, RT operating reserves, and ESI products (where appropriate), clearing prices are set at the respective shadow price for the relevant product constraint. The shadow price measures the cost to the system of obtaining an additional MWh of the given product. In cases where an incremental MWh of a product can be procured from the marginal resource, the shadow price is the same as the product offer price from that resource. In instances when the incremental MWh is met by substitution of product awards between resources, the shadow price will reflect the increase in total costs associated with these changes in supply.[37] Examples of this market clearing logic can be found in various ISO-NE presentations.[38]

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[36] The assumed change in refueling rate is consistent with the range of different daily refueling rates observed among resources currently within the market.

[37] Since resources do not provide offers for RT operating reserves, shadow prices for these products are set based on the total change in costs associated with the redistribution of resource product awards, rather than a RT operating reserve offer from a marginal resource. This approach is consistent with how RT operating reserves prices are established in New England today.

[38] ISO NE, "Winter Energy Security Improvements: Market-Based Approaches", May, June, and July 2019.

2. Customer Payments

Customer payments are estimates for each case, reflecting (1) net payments for energy to suppliers, including day-ahead payments and settlement of real-time deviations; (2) FER payments associated with the sale of DA energy; and (3) the payments for ESI products, including the day-ahead purchase of energy options and the settlement of these DA energy options against RT LMPs. The model does not consider any changes in payments to other ISO-NE-administered wholesale markets such as the FCM or the FRM. Changes in payments reflect several factors, including the changes in energy supply due to the effect of ESI incentives on energy inventories, substitution among resource-level awards that shifts the mix of resources supplying energy, and the procurement of additional services in the day-ahead market that may improve system reliability.

Day-Ahead and Real-Time energy payments are calculated based on the sum of all cleared day-ahead positions (DA LMP * quantity), minus any deviations in real-time position at the RT LMP. This cost component is calculated in the same fashion under both the CMR and ESI model runs.

FER payments are not part of current market rules, but are made to resources supplying energy when their energy supply contributes to meeting the FER under ESI. This occurs when there is a positive EIR or when the EIR is exactly zero, in which case the FER constraint is binding and (all else equal) there is a positive cost to the system to serve an incremental 1 MWh higher load forecast (as described in **Section III.B.5**). The total FER payment is the EIR price times the quantity of DA energy awards.

Net ESI product payments reflects two components. The first component is the payment to generators for supplying DA energy options to meet ESI product demand. This payment is equal to the market-clearing price of the DA energy option for each ESI product times the quantity of this product procured.

The second component accounts for settlement of the DA energy options against the RT LMP. Load is paid the option closeout cost by DA energy option suppliers, which is therefore represented as a credit to load. The option closeout cost is RT LMP minus the strike price if the RT LMP is greater than the strike price, while the closeout cost is zero if the RT LMP is less than the strike price. Closeout costs are estimated by settling historical RT LMPs against the strike price.[39] The net cost of the ESI products thus reflects these upfront option payments net of real-time closeout costs.

3. Changes in Production Costs and Energy Mix

The model analyzes changes in production outcomes, including production costs and clearing resource mix. Production costs include both modelled variable production costs (including fuel, variable operations and

[39] We calculate energy option prices and settlement using the same underlying historical distribution of prices. There are several reasons for employing this methodology. In theory, output from our production cost model could be used to calculate energy option prices and settlements. However, there are several concerns with an approach that uses modeled output to determine these prices. First, production cost models generally understate market volatility (and therefore may estimate energy option prices and settlements below their expected values), unless calibrated to capture such volatility, which our model is not. Second, because energy option offers are an *input* to our model, we cannot rely on an *output* of the model, RT LMPs, to calculate them. More importantly, when estimating prices and settlement of financial options, the larger time-series available through historical data will provide a more reliable approach than reliance on a smaller sample of real-time prices from our production cost model. And, settling an option priced using historical data with prices from a different mathematical framework (i.e., our production cost model) would create an internal inconsistency, making the prices invalid and causing the resulting settlement to have excess (or insufficient) returns.

maintenance, and emissions) and fixed costs of production. Fixed costs of production represent changes in costs associated with taking action to secure fuel incentivized by the proposed ESI rules. These fixed costs include the holding costs associated with larger end-of-winter fuel inventories and upfront LNG forward contract costs.

4. Operational and Reliability Metrics

The production cost model is designed to simulate the market clearing in the New England day-ahead and real-time energy and ancillary services markets. Thus, its primary function is to assess market outcomes, illustrating differences between current market rules and those under the ESI proposal. However, due to the design of our model and the deterministic scenario approach we take, our assessment is not designed to provide a thorough or complete analysis of reliability outcomes and may not fully capture the likelihood that extreme reliability events may occur, or the extent to which ESI would reduce the likelihood that they occur. Such impacts are typically performed through other modeling techniques and may reflect different assumptions about a variety of factors that would impact reliability outcomes, especially during stressed conditions. The model does not account for the full range of contingency events that can affect resource, transmission and fuel availability, where the contingencies for which we do account reflect average, not probabilistic, effects (e.g., using average forced outage rates rather than probabilistically sampled outage rates). Using these averages may not fully consider the heightened risks posed by such contingencies during acute periods of system stress due to constraints on fuel supplies. Our analysis also does not account for transmission topology, which can capture the locational limits and constraints that can lead to reliability concerns in particular zones or load pockets.

Furthermore, our model does not include plant commitment and dispatch and other intertemporal limits to plant operations (e.g., minimum run times and minimum down times). As a result, our model assumes smoother and more continuous plant operations than occurs under actual system operations. Finally, the model seeks to evaluate the expected market impacts of ESI and assumes a market response to stressed conditions, such as additional fuel procurements and improved fuel supply chain logistics, especially under the ESI Scenarios where the incentives to make such procurements are increased because of the additional revenue associated with the new ancillary services.

Due to the combined impact of these factors, our model may not fully capture extreme reliability events associated with any market simulation under both CMR and ESI, including the potential for reserve shortages. To the extent that ESI would increase resource incentives to be available in real-time, the analysis may therefore underestimate potential reliability benefits of the ESI proposal. Despite these limitations, we analyze several metrics related to fuel systems operations that potentially provide information related to reliability outcomes. Along with operating reserve shortages, we also measure several outcomes related to the use of the natural gas supply system and fleet-wide fuel oil inventory that seek to illustrate if ESI appears likely to increase the quantity of fuel available for electric generation, especially during stressed conditions.

IV. Impact of Energy Security Improvements on the Energy Market

The proposed ESI market rule changes would create new day-ahead ancillary services that are expected to improve both efficiency and reliability by addressing gaps in the current market. In this section of the report, we summarize the results of our assessment of the impact of the ESI proposal on the ISO-NE energy markets. Our assessment includes both quantitative estimates of impacts based on the production cost model and qualitative analysis developed through economic and market analysis. The analysis quantifies the expected impacts for particular deterministic scenarios reflecting assumptions about market and system conditions. It also illustrates the mechanisms through which ESI will impact market outcomes.

Below, we summarize our analyses' key findings regarding ESI's expected impact on market outcomes:

1. Consistent with its design, ESI would create additional incentives for resources to maintain secure energy supplies (e.g., higher levels of energy inventories). These incentives are created through two new revenue streams: FER payments for resources supplying DA energy, and revenues to compensate resources that supply the new ESI products. **Section IV.1** discusses these incremental sources of revenue, and analyzes the incremental incentives to support energy inventory.
2. ESI would provide price signals to procure the new day-ahead ancillary services. Procurement of DA energy and these new ancillary services is co-optimized, ensuring that services are procured at least cost and that price signals are consistent with the costs associated with providing this service. Our analysis reflects the gains from this co-optimization and the resulting allocation of products to different resources, given substitution possibilities and the relative cost of supplying DA energy and DA energy options. S**ection IV.1** discusses the estimated ESI prices in each Case, while **Section IV.2** discusses the mix of resources supplying ESI products.
3. ESI would better preserve energy inventory compared to current market rules. With ESI, resources can sell DA energy options and thus be compensated for maintaining energy supply in reserve, rather than using limited inventories to supply energy, which is the only source of compensation under current market rules. S**ection IV.2** discusses expected shifts in the mix of energy supplies under ESI.
4. Under ESI, the day-ahead market would be less likely to clear energy supplies that are less than the forecasted load, as compared to current market rules. And, any remaining gap between cleared supplies and forecast load will tend to be smaller with ESI. This outcome is a consequence of the auction clearing mechanism under ESI, which, as described in **Section III.B.5**, balances losses from procuring additional DA energy with cost savings from reducing the EIR quantity. **Section IV.2** shows how these shifts in DA energy supply are expected to occur under ESI.
5. ESI would be expected to increase efficiency and lower production costs, particularly under stressed market conditions when the increase in energy inventory reduces electricity production from higher cost fuels. S**ection IV.3** further discusses these changes in efficient and provides estimated production cost changes for each Case.

The ESI proposal will also have consequences for the flow of payments by load (and net revenue to resource owners) in the ISO-NE energy markets:

A. Aggregate payments by load to suppliers would be affected by ESI, although these impacts vary with market conditions. When stressed conditions are uncommon (e.g., the Infrequent Case), ESI would likely increase payments to generators from loads.

B. However, with stressed conditions, impacts would depend on two factors that affect payments in different directions. On the one hand, payments would increase for ESI ancillary services (including the FER). On the other hand, payments would decrease due to the availability of additional energy inventory supplies during tight market conditions, thus partially, fully or more than fully offsetting the cost of the ESI services. The net change in payments under stressed conditions would depend on a combination of factors, such as the nature of the stressed conditions (e.g., frequency of stressed conditions and duration of these conditions) and the market's response to ESI incentives. **Table 7** summarizes this change in payments for the three winter Central Cases.

Table 7. Summary of Change in Total Payments, Winter Central Case

		Frequent Case				Extended Case				Infrequent Case			
Product / Payment		**CMR**	**ESI**	**Difference**		**CMR**	**ESI**	**Difference**		**CMR**	**ESI**	**Difference**	
Energy & RT Operating Reserves	[A]	$4,101	$3,917	-$183	-4.5%	$2,730	$2,516	-$214	-7.8%	$1,749	$1,707	-$41	-2.4%
DA Energy Option													
DA Option Payment			$207				$113				$45		
EIR			$0				$1				$1		
RER			$67				$37				$15		
GCR10			$93				$50				$20		
GCR30			$47				$25				$10		
RT Option Settlement			-$142				-$81				-$31		
Net DA Ancillary Services	[B]		$66				$32				$15		
FER Payments	[C]		$250				$113				$61		
Total Payments	[A+B+C]	$4,101	$4,233	$132	3.2%	$2,730	$2,661	-$69	-2.5%	$1,749	$1,783	$35	2.0%

C. Changes in net revenues vary across resource types, although direction of these impacts (i.e., whether net revenues increase or decrease) is generally the same across resource types within each Case (i.e., given the nature of the stressed market conditions).

D. Estimated impacts reflect only energy and ancillary services market outcomes, and do not consider any changes in payments (and net revenues) associated with FCM or FRM that could potentially occur.

The following sections detail these results, evaluating price and incentive effects, the supply of DA energy and ESI products, production costs, total payments, net revenues, and operational outcomes. We first discuss the winter Cases, and then discuss the non-winter Cases. Unless otherwise stated, differences or changes in outcomes discussed in the sections that follow refer to differences between the ESI and CMR results for the relevant case.

A. Winter Cases

1. Prices and Incentives for Energy Supply

The ESI proposal would have a number of dynamic effects on day-ahead market clearing prices. Along with introducing new ancillary service products, LMPs for DA energy will be affected by the new interactions among day-ahead products under the proposed design. The resulting price signals would create incentives for resource owners to efficiently supply services to the region, particularly the reliable delivery of energy supply in real-time. Thus, in this section, we consider these price impacts and their effects on incentives in tandem.

In principle, improvements in the reliable supply of real-time energy can be made through many actions. Our quantitative analysis considers improvements in energy inventory, including increasing the quantity of liquid fuel held in on-site storage tanks and contracting for more-firm delivery of fuel, such as through a forward contract with an LNG terminal. In practice, we expect that these changes reflect a subset of the actions market participants would take to improve their ability to deliver energy in real-time. More specifically, ESI's incentives would likely affect many other types of actions that would have consequences for resources' ability to supply energy in real-time, such as preservation of limited energy inventories (e.g., at hydropower facilities),[40] investment that expands potential fuel storage (e.g., retrofitting gas-only plants for dual-fuel), general improvements in operational performance (e.g., other contractual arrangements for fuel, reducing forced outage rates), and the internalization of the potential ESI revenues (and costs) in entry and exit decisions.

For each of these decisions, resource owners go through a process of balancing various tradeoffs that have implications for the reliability of energy supply in real-time. For example, owners of resources with stored fuel supplies would balance the costs of investing in additional energy inventory against the benefits of this additional investment, in terms of increased market returns. When making this assessment, ESI would increase generator incentives to secure energy inventory relative to current market rules through two new sources of return.

- ***FER payments***. FER payments would provide incremental revenues to resources supplying DA energy. Thus, as resource owners consider the costs and benefits to holding additional fuel inventory (at the margin), FER payments would increase the return to holding additional inventory compared to current market rules, causing them to increase their inventory relative to current market rules. These decisions to hold additional inventory would manifest themselves in an increase in DA energy supply when the supply a resource might otherwise offer would be limited by its fuel inventory. Such increases in supply are most likely to occur during stressed market conditions, when fuel supplies are most limited and the economic gains (increased revenues) and reliability benefits from holding fuel supply are greatest.
- ***ESI products.*** By providing a new means to be compensated for the reliability benefits provided by energy inventory, the sale of DA energy options to satisfy ESI product requirements provides a means

[40] While the model allows fossil fuel resources with limited inventories to preserve their fuel via opportunity cost bidding, for 'profiled' limited energy resources, such as pump storage facilities, the model assumes that their energy production is constant between CMR and ESI. This methodology is discussed in more detail in **Section II.B.3**.

for resources with energy inventory (e.g., fuel supplies) to earn a return on this inventory, even if it is not consumed. Thus, at the margin, holding more fuel supply than resources would under current market rules provides additional revenue streams through the sale of DA energy options.

Along with providing the capability to support a DA energy option through the delivery of real-time energy, energy inventory can lower a resource's financial risk from selling a DA energy option. Thus, a resource with energy inventory can submit a more competitive offer for a DA energy option, making it more likely to receive an award. In turn, the financial risk, and as a result, the financial cost, may be reduced when taking a DA energy option award, providing a greater return to the energy option award.

The quantitative analysis in **Section IV.1.c)** and **Section IV.1.d)** illustrate the benefits of additional revenue streams created by ESI to support incremental energy inventory.

a) Payments to DA Energy Supply

Under ESI, the change in payments to resources that supply DA energy will reflect the net impact of several different factors. These effects derive from different aspects of the ESI design, with some increasing payments to DA energy and others decreasing payments. Our quantitative analysis captures the net impact of these different effects, which in aggregate may lead to either a positive or negative impact on payments to DA energy.

First, under ESI, resources awarded DA energy positions earn FER payments, in addition to the LMP, which will tend to increase compensation for DA energy provided. FER payments are incremental payments made to compensate generation that sells energy in the day-ahead market for helping to meet the FER requirement. These payments compensate resources that supply DA energy for their contribution to meeting the FER requirement, and ensure that resources supplying energy are no worse off for selling DA energy rather than a DA energy option (i.e., the awards are incentive compatible).

Second, ***with the FER constraint, the market will clear a larger quantity of DA energy under ESI compared to current market rules, although this effect would not be expected to meaningfully change DA LMPs***. As described in **Section III.B.5**, the total quantity of DA cleared energy will tend to increase under ESI. Our quantitative estimates of this impact are provided in **Section IV.2**. However, because ESI does not directly change RT LMPs, we would not expect this effect to produce any change in DA LMPs, assuming market participants would trade (arbitrage) on any predictable and meaningful difference between DA LMPs and RT LMPs until such differences are eliminated.[41] **Section III.B.5** describes these interactions in greater detail.

Third, co-optimization of all products in the day-ahead market can also lead to substitutions among products that can affect market clearing for DA energy. Because the optimization under ESI satisfies constraints for multiple DA products, the positions for each service awarded to a given resource will depend, among other things, on the relative offer prices from that resource for each of the services. The result is that

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41 While we would not expect DA LMPs to change from the combined effect of the FER constraint and increase in demand in response to that constraint, DA LMPs would be expected to change due to increase in energy supply in response to the incentives created by ESI, an effect that is described below.

the lowest cost offers for DA energy may not always be awarded a DA energy position. For example, a more-costly DA energy offer may clear over a lower-cost DA energy offer if the resource with the lower-cost offer creates more cost savings (social surplus increases) by supplying a DA energy option rather than DA energy.[42] In addition, given differences in energy inventories and different substitution possibilities, opportunity costs for energy limited resources (in both day-ahead and real-time) will differ between the ESI and CMR cases.

Each of these impacts is driven by changes to market-clearing with the addition of the new ancillary services. But, we also expect ESI's incentives to lead to an increase in energy inventory, which will have implications for payments to energy.

Fourth, an increase in energy inventory under ESI* would be expected to *reduce* LMPs, all else equal*, which will tend to reduce compensation for DA energy provided. In effect, ESI would increase energy supply, which can lower LMPs during tight market conditions when the market would otherwise rely on higher-cost resources. This indirect effect, the reduction in LMPs, would be expected to reduce any increases in compensation for DA energy discussed by the first factor above, and will dampen the direct effect of ESI's incentives. Such "equilibrium" adjustments by the market to new incentives occur with any change in policy or regulation.

Table 8 provides the change in payments to energy for the three Central Cases in ESI compared to CMR. Changes reflect both the change in LMPs and the additional FER payments. Across all three winter Central Cases, DA LMPs are reduced by $1.20 per MWh (Infrequent Case) to $6.43 per MWh (Extended Case). These LMP changes are the result of the combination of factors identified above, although the most important factor is the incremental energy inventory that the model assumes under ESI (i.e., the fourth factor identified above).

In the Infrequent Case, after including the FER payments, total payments to DA energy (i.e., the change in the DA LMP plus FER payments) increase by $0.74 per MWh. Without any periods of system stress, the additional supply of energy inventory incented by ESI has a smaller downward effect on LMPs. Consequently, compensation to energy supply for its contribution to meeting the FER leads to an increase in net payments to DA energy.

In the two Cases with stressed conditions, we find different impacts: in the Frequent Case, average net payments to DA energy increase by $2.27 per MWh, whereas, in the Extended Case, average net payments decrease by $2.88 per MWh. In both of these cases, additional energy supply incented by ESI has a downward effect on LMPs. In the Frequent Case, as in the Infrequent Case, the payments for FER outweigh the reductions in LMPs. In the Extended Case, however, this downward LMP effect outweighs the cost of compensating for contributions to meeting the FER, resulting in a net reduction in payments per MWh.

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[42] For example, assume Resource A offers DA energy at $50 per MWh and a DA energy option at $12 per MWh, while Resource B offers DA energy at $45 per MWh and a DA energy option at $5 per MWh. Under current market rules, Resource B would supply DA energy before Resource A due to its lower offer. Under ESI, if the system requires one resource to provide DA energy and the other DA energy options, the optimization would award Resource A energy and Resource B energy options because the total cost of doing so ($55 = $50 for A's energy plus $5 for B's option) is less than the alternate scenario where lower cost B supplies energy ($57 = $45 for B's energy plus $12 for A's option).

Table 8. Average DA Payments to Generators, Winter Central Case
CMR vs ESI ($ per MWh)

	CMR	ESI				Change	
	Day-Ahead LMP	Day-Ahead LMP	FER	Day-Ahead LMP+ FER	Real-Time LMP	Day-Ahead LMP	Day-Ahead LMP + FER
Case	[A]	[B]	[C]	[D]=[B]+[C]	[E]	[B]-[A]	[D]-[A]
Frequent Case	$127.40	$121.91	$7.76	$129.67	$121.60	($5.49)	$2.27
Extended Case	$85.15	$78.72	$3.55	$82.27	$79.73	($6.43)	($2.88)
Infrequent Case	$54.97	$53.77	$1.94	$55.71	$55.86	($1.20)	$0.74

b) Prices for ESI Ancillary Services

The ESI proposal introduces new DA energy option products to the New England energy markets. **Table 9** reports average award prices for these products for the Central Cases. These prices are weighted averages, reflecting the quantity of each product procured in each hour. These quantities are assumed to be the same in all hours for GCR10, GCR30 and RER, although in actuality these quantities may differ from hour to hour to reflect changes to the potential size of system contingencies and other factors. By contrast, the quantity of EIR procured in each hour is dynamically determined by the model (given tradeoffs from substitution of DA energy for EIR), varies from hour to hour, and is zero in a large fraction of hours because the substitution between products leads the day-ahead optimization to procure enough energy to meet the forecast load.

Table 9. Weighted Average DA Energy Option Clearing Prices, Winter Central Case
($ per MWh)

	($/MWh)			
Case	EIR/FER	GCR10	GCR30	RER
Frequent Case	$69.11	$27.03	$27.03	$24.91
Extended Case	$47.74	$14.51	$14.45	$13.49
Infrequent Case	$8.36	$5.77	$5.75	$5.75

Average prices for GCR10, GCR30 and RER vary due to differences in resources' ability to supply each product. Procuring 'higher quality' ESI products (e.g. GCR10) may require accepting higher-priced offers from resources that can provide these services, which would increase their market-clearing price relative to the clearing price for 'lower quality' products. For example, because fewer resources are able to receive a GCR10 award, as compared to the other DA energy options, these prices are higher, reflecting the need to accept higher priced offers to meet the GCR10 requirement in some hours.

Prices vary across Cases, driven by several factors. First, the quantity of DA supply (energy and energy options) differs across cases, with the largest quantities in the Frequent Case and the smallest quantity in the Infrequent Case. When a larger DA supply is needed, prices will be higher, all else equal, because the market clears at a higher point on the DA energy and DA energy option supply curves. At the extreme, DA energy option product shortages may occur, when their prices are set by the penalty factor values. Thus, Cases with higher DA energy option product prices are due, in part, to a larger number of RER shortages. Second, expected closeout costs are highest when price volatility is greatest, though in such cases, the higher option price may be offset by larger expected closeout costs. Thus, the option prices are greatest in the Frequent

Case, which experience more hours with high levels of price volatility than in the winters in which volatile market conditions are less frequent.

Average EIR prices differ from the other ESI products because the quantity of EIR procured varies from hour to hour, and because EIR prices tend to be greatest in hours in which the EIR quantity is largest (i.e., EIR prices and quantities are positively correlated). **Table 10** provides further detail on the different outcomes for EIR/FER prices. The EIR/FER price is greater than zero whenever the FER constraint is binding. But, this constraint can bind when the EIR quantity is greater than zero and when it is *exactly* equal to zero (represented as "> 0" and "= 0" in the **Table 10**). The latter case occurs when the auction mechanism substitutes DA energy for EIR until EIR is exactly equal to zero, but the constraint continues to bind because increasing the load forecast would cause an immediate gap between cleared energy and the load forecast. In such cases, the price (i.e., "shadow price") associated with this constraint is positive and DA energy is compensated for keeping the EIR at zero. That is, decreasing DA energy would cause EIR to be positive, thus imposing a cost to procure energy options.

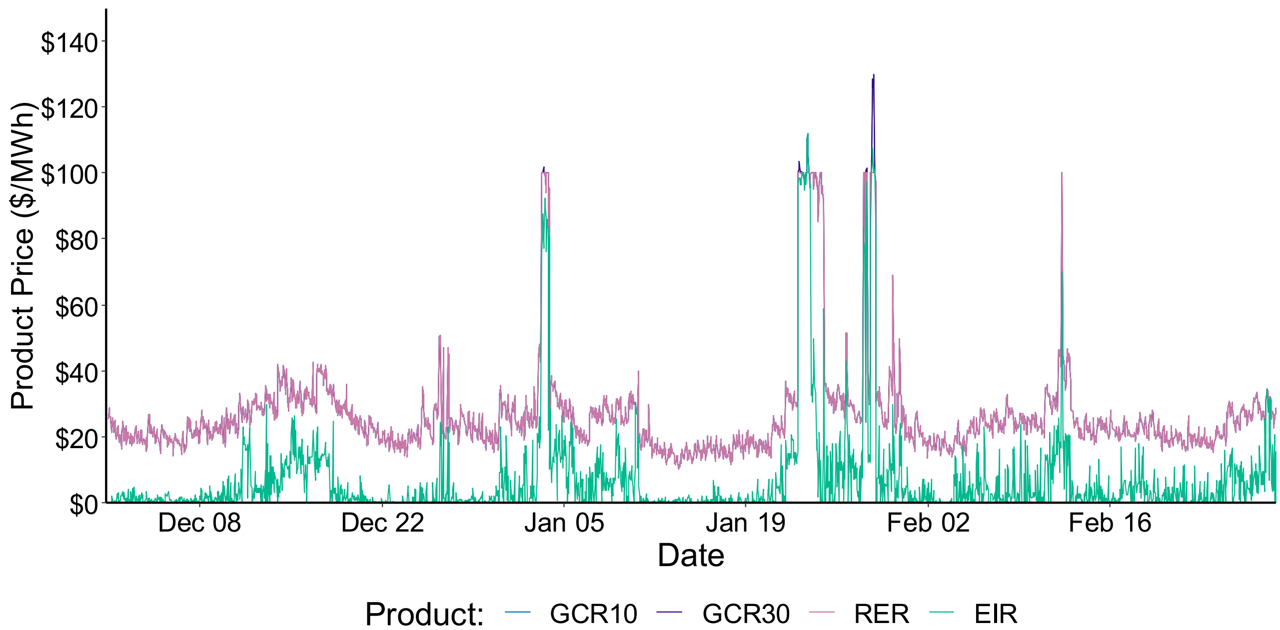
After accounting for adjustments to the EIR due to substitutions of DA energy for EIR, there is a positive quantity of EIR in a relatively small share of hours, ranging from 3% in the Frequent Case to 16% in the Infrequent Case. Hours when EIR is exactly zero, but the EIR price is positive, represents a large fraction of hours, ranging from 42% in the Extended Case to 72% in the Frequent Case. Hours in which cleared energy is greater than the forecast accounts for the remaining hours – 24% in the Frequent Case to 51% in the Extended Case.

Table 10. Frequency of EIR Quantity-Price Outcomes by Winter Central Case

ISO Forecast Load minus Cleared Energy Supply	EIR Quantity	EIR/FER Price	Frequent Case	Extended Case	Infrequent Case
> 0	> 0	> 0	3%	7%	16%
= 0	= 0	> 0	72%	42%	45%
< 0	= 0	= 0	24%	51%	39%

The average prices in **Table 9** mask hourly variation in prices within Cases. **Figure 15** illustrates this hourly variation for the Frequent Case, where it graphs prices for each of the four DA energy options. As we describe below, this hourly variation is an important element of the ESI proposal, as it signals periods of greatest need for energy inventory and compensates resources able to provide supply during these periods.

Figure 15. Estimated ESI Product Prices by Hour, Winter Central Frequent Case



c) Incentives for Investment in Incremental Fuel Oil

Under current market rules, oil-only and dual fuel generators have an incentive to hold fuel inventory so that they can earn revenues by converting this fuel into electricity and be compensated at the DA or RT LMP. Generally, we would expect these units to add fuel oil to their tanks up until the expected net revenues from additional fuel oil is outweighed by its expected incremental costs.

This same cost/benefit logic will continue to hold under ESI. However, ***ESI would increase the revenue streams earned from holding oil, thus incenting these resources to increase the quantity of fuel oil held in inventory relative to current market rules.*** More precisely, holding fuel inventory incurs additional costs given the risk that such inventory will need to be held for an extended period of time. This risk is relevant in New England, where in recent years, market prices have rarely supported power generation by fuel oil outside the winter months. On the other hand, additional fuel inventory may increase the resource's ability to supply energy and reduce its costs (and risks) of taking day-ahead positions. At present, these benefits are driven by the opportunity to earn margins (revenues in excess of costs) for selling power. With ESI, these margins would be increased by the FER payments associated with the sale of DA energy, and additional net returns earned through the sale of DA energy options.

Below, we analyze – through two different, but related avenues – the incentives for resources to make investment to improve their ability to deliver energy in real-time. First, we analyze the change in total returns from holding fuel oil under ESI, showing that these new revenues are large, particularly relative to the change in costs from holding additional fuel. Second, we analyze the price signals driving these incentives at the margin, particularly during stressed market conditions.

i. Change in Total Returns to Holding Fuel Oil under ESI

Table 11 to **Table 13** compare the new ESI revenues to the change in inventory costs for the quantity of incremental fuel ESI is assumed to incent.[43] New ESI revenue streams include FER payments and DA energy options. In these calculations, the DA energy option revenues reflect only the risk premium component of the marginal offer that sets the clearing price, but not the remainder, which corresponds to the closeout cost that the generator expects to pay back (on average) to load in the second part of the option settlement. The tables also show the change in economic costs of incremental energy inventory, measured by the financial ("holding") costs of having more fuel in inventory at the end of the winter because of decisions to increase inventory during the winter.

The tables demonstrate that the average incremental payments to resources under ESI generally far outweigh the additional holding costs. These results are indicative of the incremental returns to holding greater fuel oil due to ESI, and one illustration of the strong incentives created by the ESI proposal.[44] In the Frequent or Extended Cases, these ESI revenues far exceed the change in holding costs for all fuel-oil resource categories evaluated. For example, for Dual Fuel, Combined Cycle Units in the Frequent Case, the incremental cost of holding a larger quantity of fuel at the end of the winter because of more aggressive refueling under ESI is $14 per MW of capacity. By contrast, the additional revenues earned because of ESI compared to current market rules are $5,591 per MW of capacity ($5,452 and $139 per MW for FER payments and DA energy options, respectively), for a net increase in revenue of $5,577 per MW ($5,591 per MW in incremental revenues less $14 per MW in incremental costs).

In the Infrequent Case, where conditions are generally mild and the total quantity of oil burned is modest, the net change in revenues is lower for all technology types, and even negative for the oil-only, steam resources. However, while oil-only, steam resources incur losses in this Case, they still incur positive gains that are larger in magnitude in the winters with more frequent stressed conditions (i.e., the Frequent and Extended Cases). Thus, the precise quantity of incremental fuel inventory incented by ESI may differ from that assumed by our analysis, and may depend on a combination of factors, including resource owners' expectations about future winter market and weather conditions.

These results demonstrate that the additional revenues in the market from ESI far exceed the change in costs of holding additional fuel, and provide one illustration of the incentives ESI creates for oil resources to increase the quantity of fuel held during the winter. This incremental oil will improve the region's energy security and help maintain system reliability during periods of system stress.

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[43] Incremental fuel quantities under ESI are discussed in **Section III.C.2**.

[44] As discussed above, as market participants determine the financially optimal quantity of fuel to hold, the new ESI revenues will increase the returns to holding more, rather than less, fuel in inventory, because the revenue earned from holding that fuel in inventory is greater than it otherwise would be under current market rules, thus offsetting the cost of holding additional fuel.

Table 11. New ESI Revenues and Change in Holding Costs, Winter Central Frequent Case

Technology Type	Number of Units	Change in Holding Costs ($ / MW)	ESI FER Payments ($ / MW)	ESI DA Energy Option Revenue ($ / MW)	Change in Net Revenue ($ / MW)
Dual Fuel, Combined Cycle	17	-$14	$5,452	$139	$5,577
Dual Fuel, CT	14	-$118	$5,875	$2,172	$7,929
Oil Only, CT	70	-$134	$1,784	$5,735	$7,385
Oil Only, Steam	13	-$1,257	$6,207	$583	$5,532

Note: Combustion Turbine (CT) category includes CT's and internal combustion units.

Table 12. New ESI Revenues and Change in Holding Costs, Winter Central Extended Case

Technology Type	Number of Units	Change in Holding Costs ($ / MW)	ESI FER Payments ($ / MW)	ESI DA Energy Option Revenue ($ / MW)	Change in Net Revenue ($ / MW)
Dual Fuel, Combined Cycle	17	-$112	$2,113	$61	$2,063
Dual Fuel, CT	14	-$124	$1,760	$1,199	$2,835
Oil Only, CT	70	-$88	$654	$2,032	$2,598
Oil Only, Steam	13	-$1,291	$2,646	$98	$1,453

Note: Combustion Turbine (CT) category includes CT's and internal combustion units.

Table 13. New ESI Revenues and Change in Holding Costs, Winter Central Infrequent Case

Technology Type	Number of Units	Change in Holding Costs ($ / MW)	ESI FER Payments ($ / MW)	ESI DA Energy Option Revenue ($ / MW)	Change in Net Revenue ($ / MW)
Dual Fuel, Combined Cycle	17	-$254	$785	$12	$543
Dual Fuel, CT	14	-$435	$150	$444	$159
Oil Only, CT	70	-$84	$7	$720	$643
Oil Only, Steam	13	-$1,315	$94	$3	-$1,218

Note: Combustion Turbine (CT) category includes CT's and internal combustion units.

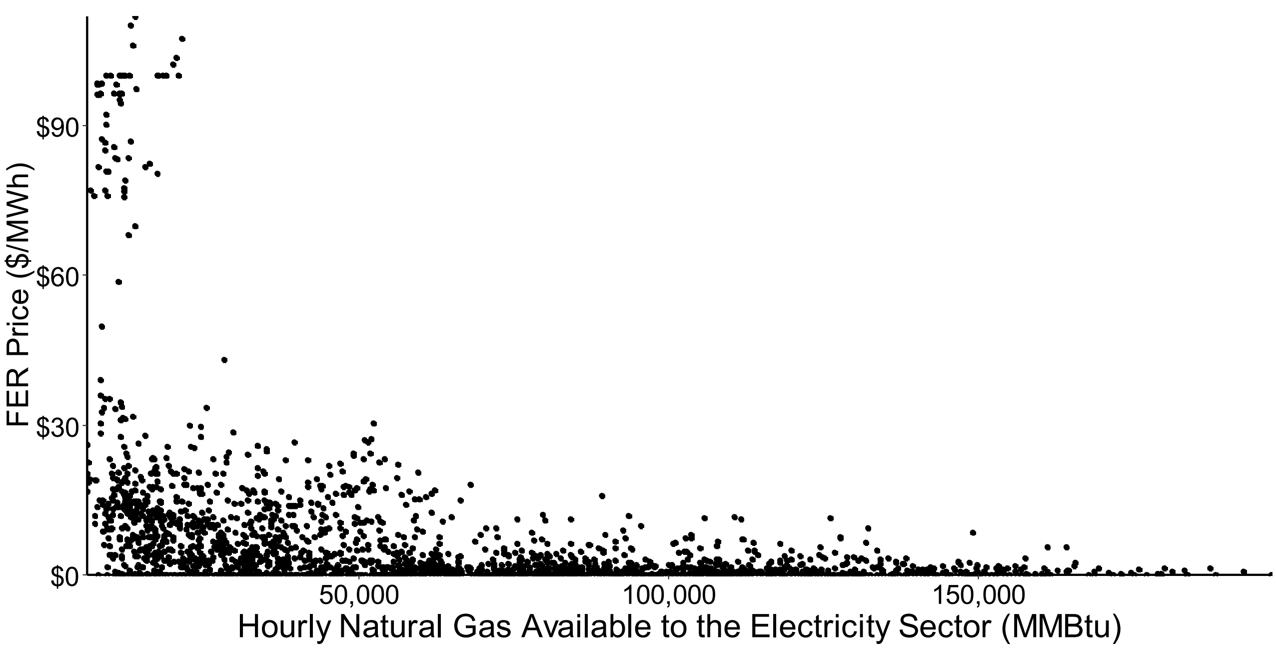
ii. Marginal Incentives for Energy Security

While the tables above estimate the change in total returns from holding fuel under ESI in each of the Central Cases, ***this incentive can also be assessed by evaluating the marginal revenues that ESI creates during periods of system stress.*** As with any market design, price signals for the desired service should be strongest when the need for these services is greatest. In this case, high prices for ESI services occur during tight market conditions when reliability needs are greatest and the higher cost offers must be relied on to supply ESI services. These high prices create strong incentives for resources to take the actions necessary to be able to provide options or energy at these times of need and to do so at lower cost than the marginal resource, thus allowing them to earn inframarginal revenues.

While we analyze these incentives in the context of decisions by oil-fired resource owners, it is important to remember that these incentives are not limited to specific generation technologies, and extend to any resources able to take actions to improve their ability to deliver energy supplies. Many resources can take actions to improve their ability to deliver energy supplies in real-time, including gas-fired resources (e.g., through forward fuel contracting arrangements, dual-fuel retrofits), hydropower resources (e.g., through preservation of reservoir levels), and demand-response resources.

Analysis of market outcomes shows that new revenue opportunities from ESI, including additional FER payments and returns from DA energy options, are greatest when market conditions are tight. **Figure 16** plots the FER price (on the y-axis) and the natural gas supply available to the electricity sector, a metric of system stress, (on the x-axis) for each hour in the Frequent Case. When natural gas supplies are limited (i.e., further left on the figure), causing high natural gas prices, fuel oil resources will be most competitive for supplying DA energy and DA energy options because their fuel costs remain fixed, regardless of upward movements in natural gas prices. As shown in the figure, FER prices are highest in these stressed conditions when the natural gas available for electric generation is low. Thus, the incentives ESI would create for greater fuel inventories would be strongest when reliability needs (e.g., natural gas limitations) are greatest and the value of additional fuel inventory for reliability is greatest.

Figure 16. FER Prices and Electricity Sector Natural Gas Supply, Winter Central Frequent Case



We analyze prices across the Cases and ESI products to assess the range of incentives to improve real-time delivery of energy supply. **Figure 17** provides hourly FER prices for each of the Central Cases. This figure (and those that follow) shows the distribution of prices, identifying the number of days (on the x-axis) that FER prices reach a given value (on the y-axis) for each Central Case. The figure highlights the large number of hours in which large FER payment rates exceed various values (e.g., above $20 per MWh) during the stressed conditions cases. For example, in the Frequent Case, the FER price exceeds $20 per MWh for 154 hours (on 28 different days) over the course of the winter. By contrast, FER payments reach high levels less frequently in the Infrequent Case, although they still exceed $10 per MWh in 93 hours (on 16 different days) over the winter. For resources earning FER payments, these revenues go directly to their profit margins, as these payments are in addition to the LMP.

Figure 17. Distribution of FER Prices, Winter Central Case

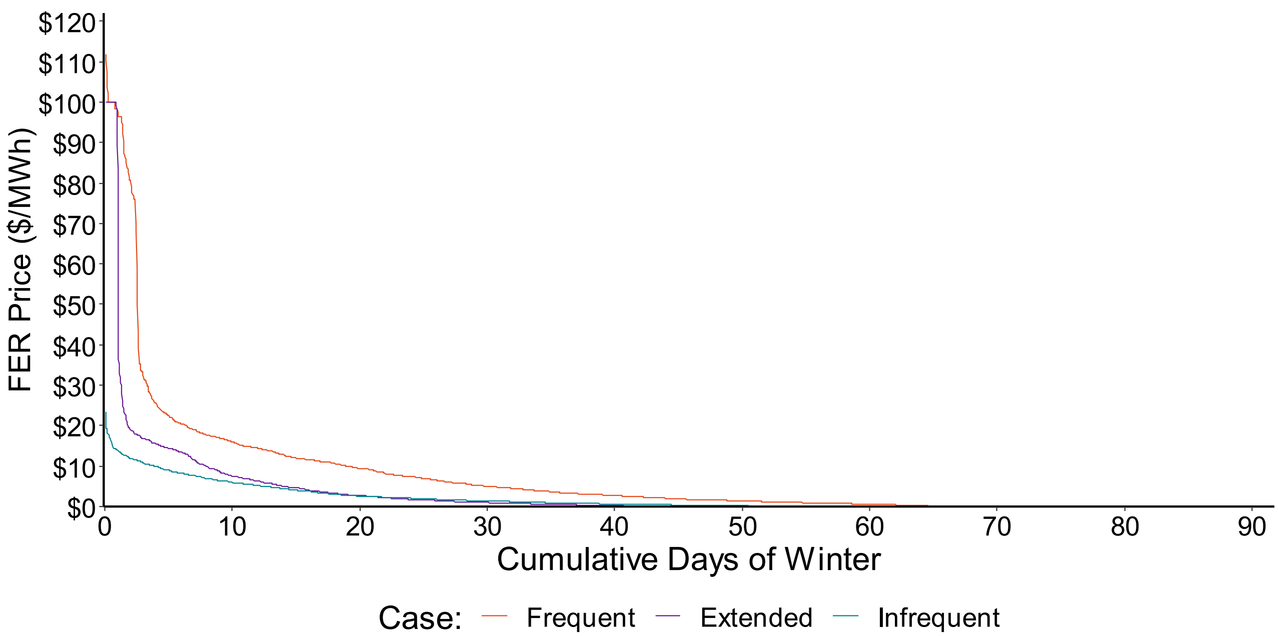


Figure 18 provides a similar hourly curve of GCR10 prices for each of the Central Cases. Consistent with the distribution of FER prices illustrated in **Figure 17**, GCR10 prices become elevated in many hours during the stressed cases, with prices exceeding $50 per MWh. **Table 14** provides another lens on the ESI price data, providing RER prices at various statistical percentiles within the hourly sample of hours. For example, in the Frequent Case, the 96th percentile RER price is $50.75 per MWh, indicating that prices are $50.75 per MWh or greater in 4% (100% minus 96%) of the hours. As there are 2,160 hours in the winter we analyze, this implies that RER prices are above $50 per MWh in at least 86 hours. In the Extended Case, prices are above $50 per MWh in 27 hours. Thus, even after accounting for the incremental energy incented by ESI, which will tend to reduce energy and ancillary service prices, DA energy option prices reach high levels in a sufficiently large number of hours to provide meaningful incentives for resources to take actions to improve their ability to deliver energy during such stressed conditions.

Figure 18. Distribution of GCR10 Prices, Winter Central Case

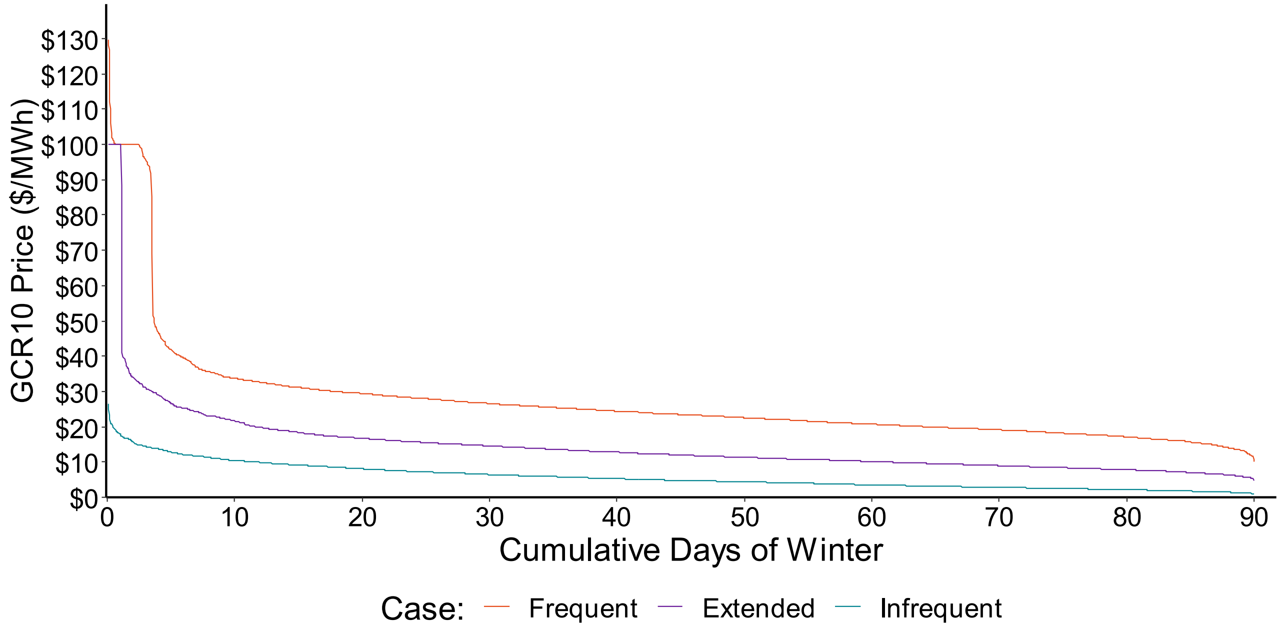


Table 14. Summary Statistics of RER Prices, Winter Central Case

	RER Percentile ($/MWh) Including Shortage Hours								
Cases	**25%**	**50%**	**75%**	**90%**	**95%**	**96%**	**97%**	**98%**	**99%**
Infrequent	$2.94	$4.76	$7.63	$10.66	$13.20	$13.92	$14.45	$16.13	$18.05
Extended	$9.26	$11.98	$16.05	$22.30	$26.99	$28.88	$30.65	$33.79	$100.00
Frequent	$19.51	$23.45	$28.63	$34.40	$43.91	$50.75	$97.54	$100.00	$100.00
All Cases	$6.88	$12.64	$21.21	$28.44	$32.90	$34.31	$37.56	$44.67	$100.00

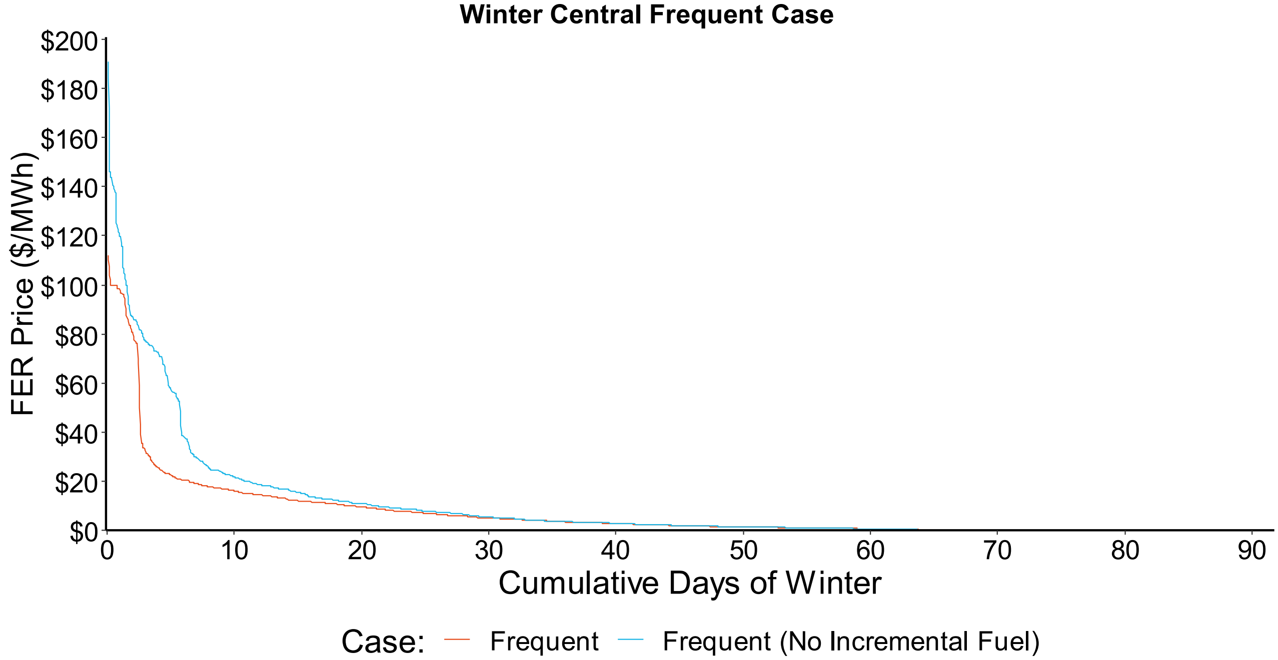
These tables and figures illustrate that ***the returns to incremental inventory are large when this inventory is available during these periods of system stress and therefore provides the greatest reliability benefit.*** For example, consider a unit that consumes residual fuel oil with a heat rate of 9,000 Btu/kWh. If the resource does not consume the fuel during the winter, it incurs a holding cost of approximately $13 per MWh to keep the fuel in inventory until the next winter.[45] However, if it consumes the fuel, then the resource earns a return equal to the incremental market revenues net of its production costs. Under current market rules, these revenues only include the LMP. But, under ESI, revenues would also include FER payments and the opportunity to supply DA energy options (which can be earned even in cases when the fuel is not ultimately used). As shown above, during periods of system stress, the ESI prices can be large, more than offsetting the holding cost. For example, in the Frequent Case, FER payments, which are made to resources that sell DA energy in addition to the DA LMP, exceed $13 per MWh in a large fraction of hours. Thus, investment in fuel

[45] This calculation also assumes $9.64 per MMBtu for refined fuel oil, and a holding cost of 15%. See the appendix for a more detailed explanation of how this value is calculated.

inventory can allow the resource owner to reap additional returns during periods of system stress, thus improving the reliability and enhancing the region's energy security.

In these exhibits, the frequency of high FER and ESI prices already reflects the incremental fuel supplies assumed under the ESI case. Thus, even after accounting for the effect on prices of assumed incremental fuel supplies under ESI, price signals for the ESI products remain strong in a meaningful fraction of hours. If our modeling had assumed no meaningful market response to the introduction of the ESI products, the frequency of these high prices would be even greater because less available fuel oil would decrease the energy supply and increase market prices. This suggests that resources that use fuel oil would have even stronger financial incentives to add oil to their tanks in response to the new products if the broader market response to ESI was more limited. This observation is demonstrated graphically in **Figure 19**, which shows the FER prices with and without the incremental fuel supplies assumed under ESI. As shown, absent the incremental fuel supplies, high FER prices are much more frequent, showing that the incentives to procure oil to sell DA energy (and ancillary services) would be even greater absent a robust market response.

Figure 19. Distribution of FER Prices with and without Incremental Fuel
Winter Central Frequent Case



The particular design of ISO-NE's ESI proposal also has important consequences for the strength of the incentives it would create. During the stakeholder process, market participants raised the possibility of various changes to the ISO-NE proposal, such as eliminating certain ESI products from the design. Each of these changes would have consequences for the prices for each ESI product, which in turn would affect the incentives for market participants to incur costs to improve their real-time delivery of energy, consistent with ESI's objectives. For example, one change that has been discussed is the elimination of the RER. **Figure 20** and **Figure 21** illustrate the consequences of this proposal, in terms of the effect on incentives for energy inventory. Specifically, these figures show the distribution of prices for FER and GCR10 for the Central Frequent Case with and without the RER. In this no RER case, we assume that the additional energy inventory incented by ESI is only one-half the amount that would be incented with the full ESI proposal. (The details of this scenario are discussed further in our Scenario Analysis in **Section IV.C**.) Despite the assumption that the No RER scenario incents a lesser quantity of incremental energy inventory, the price of both FER and GCR10 is substantially lower without RER as compared to when RER being included in the ESI proposal. This difference in price levels demonstrates that the elimination of the RER from the ESI design would materially reduce the incentives for resource owners to take steps to improve their ability to deliver energy in real-time.

Figure 20. Distribution of FER prices with and without RER
Winter Central Frequent Case

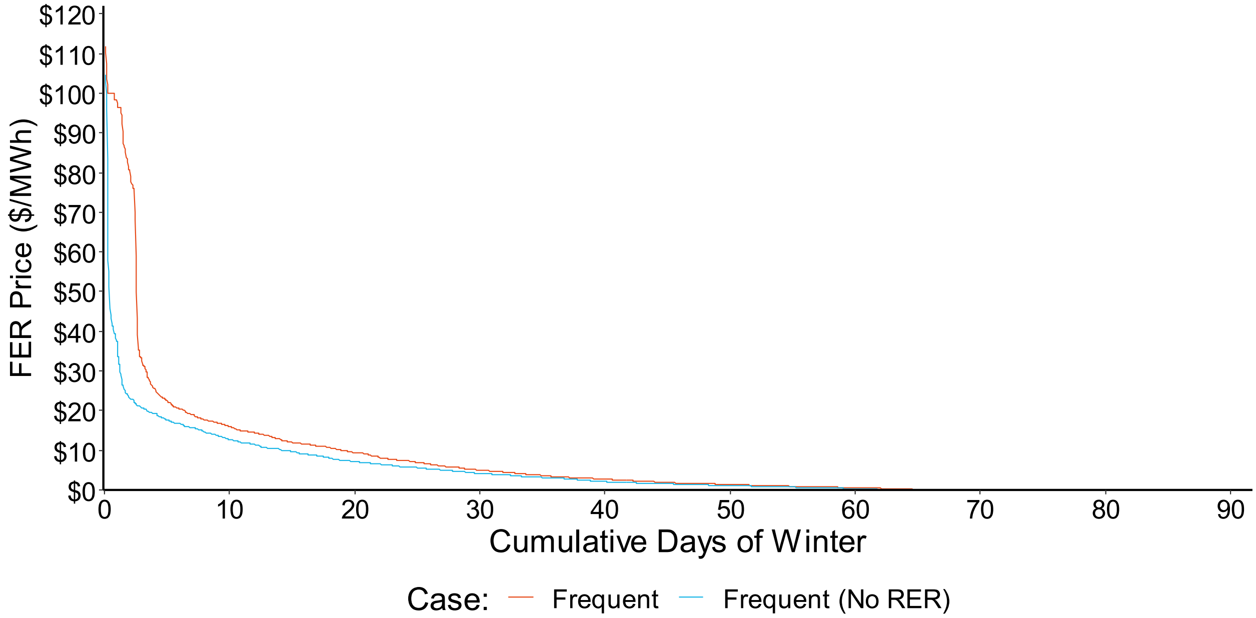
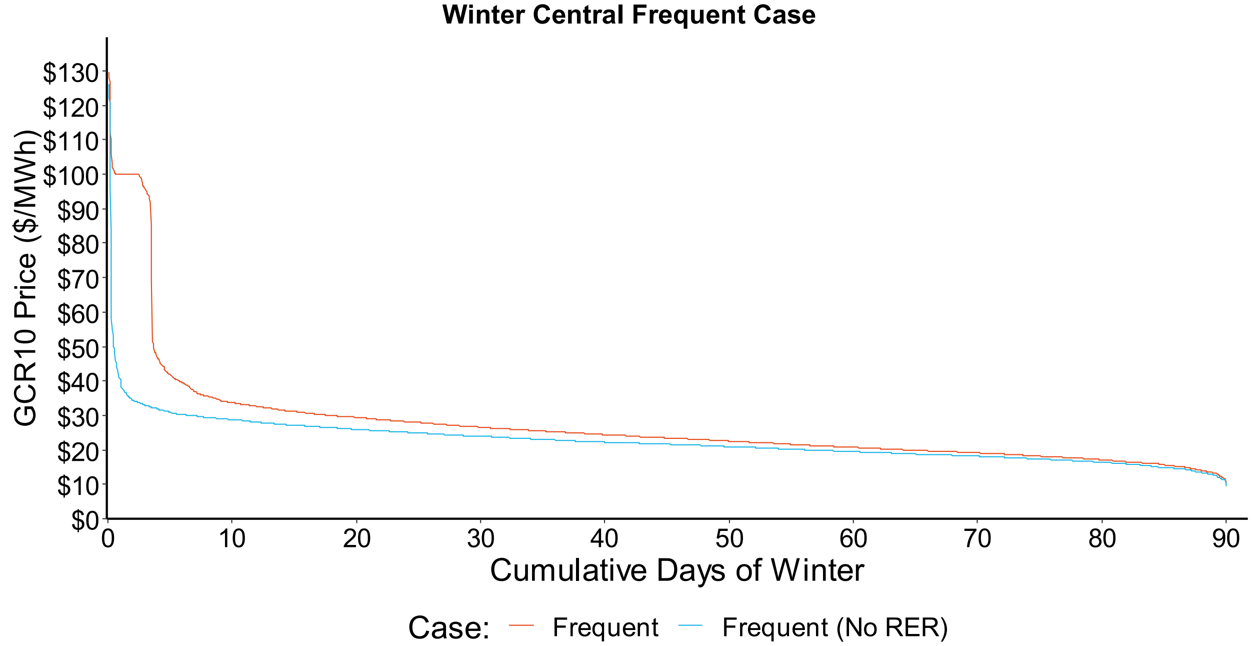


Figure 21. Distribution of GCR10 prices with and without RER
Winter Central Frequent Case



These results also show that the assumed incremental fuel inventory incented by ESI appears consistent with plausible responses by market participants. **Figure 16** to **Figure 19** demonstrate the new financial incentives created by ESI improve delivery of real-time energy during stressed system conditions. These figures show that, even after accounting for incremental inventory incented by ESI, there are still opportunities to earn substantial returns from supplying DA energy and DA energy options during periods of system stress by increasing the holding of fuel oil.

In total, analysis of hourly FER and ESI product pricing demonstrates the strong incentives that would be created by the ESI proposal. ***If adopted, ESI would expose market participants to greater financial risk if they sell forward positions that are not backed by physical inventory. These price signals would be strongest during stressed conditions, providing price signals that are aligned with the periods of need. During these periods of need, the incentives to take steps to improve deliverability will be greatest for those resources with the greatest risk of having fuel inventories reduced to the point that it constrains supply decisions, illustrating that ESI's incentives efficiently target those opportunities to increase inventory that would provide the greatest value to system reliability relative to their incremental costs.***

d) Incentives for Investment in Incremental Forward LNG Contracts

In addition to assessing ESI's impact on incentives to hold fuel oil, we also analyze the changes in incentives for a gas-only resource to enter into a forward contract with an LNG terminal under ESI as compared to current market rules. In contrast to fuel-oil inventory and refueling decisions, which are relatively continuous, these forward contracting decisions are more discrete, requiring resource owners to make a "yes/no" decision prior to the winter about entering into a contract. While ESI will increase the expected net revenues associated with forward LNG contracts, and may therefore increase the likelihood that gas resources enter into such contracts, the discrete nature of these contractual decisions, among other reasons, makes it more difficult to estimate the extent to which ESI will increase the amount of LNG available to the region through additional forward contracting.

At present, the LNG terminals have entered into various forward contracting arrangements with LDCs, some generators, and potentially other market participants. LNG terminal owners have indicated that they have the physical capability to expand forward contract volumes with New England market participants.

ESI would provide additional incentives for market participants to enter into additional forward contract volumes with the LNG terminals. Like the fuel oil resources analyzed in the prior section, these additional revenues potentially come through FER payments and the sale of DA energy options. **Table 15** provides our analysis of the potential incremental revenues under ESI to the holder of a forward LNG contract.[46] In this analysis, the resources assumed to hold the forward contract clear all of the energy supply supported by these contracts through DA (and RT) energy, but supply no DA energy options. This pattern of supply reflects a combination of factors, including the timing and severity of stressed market conditions in the particular winter Cases evaluated. Thus, the potential gains considered in our quantitative analysis reflect only incremental FER

[46] These revenues reflect an assumed forward contract with a strike price of $10 per MMBtu, 10 calls and no take-or-pay obligation. In practice, generators and LNG terminals may enter into different contract structures. To the extent that these alternative contract structures are preferred, they may provide greater net benefits, and thus present a lower gap to contracting than the estimated gap assuming the call option contract structure.

payments, although, as we describe below, we expect other incremental benefits that are not captured in our analysis.

In the cases representing stressed market conditions, ESI would provide incremental revenues of $2,066 and $1,511 per MW in the Frequent and Extended Cases, respectively. The analysis assumes that the resource with the forward LNG contract would use the fuel to supply incremental DA energy that it otherwise would not supply without the forward LNG contract. In this sense, our quantitative estimates may provide an upper bound on the incremental FER revenues from the direct use of the forward LNG contract supplies.[47] By contrast, there are no incremental revenues in the Infrequent Case because weather conditions are so mild that gas prices are not high enough to exercise any calls on natural gas supplies under the contract.

Table 15. Forward LNG Contract, Incremental ESI Revenues from FER Payments, Winter Central Case

Severity	FER Hours	FER Price [A]	FER MWh [B]	FER Payments ($) [C] = [A]*[B]	FER Payments ($/MW)
Frequent Case	240	$8.70	146,311	$1,273,243	$2,066
Extended Case	240	$6.36	146,311	$931,241	$1,511
Infrequent Case	0	NA	0	$0	$0

The quantitative analysis captures some but not all of the potential gains from a forward LNG contract under ESI. It may therefore understate the incremental incentives that ESI provides to enter into such contracts. One issue is the relatively simple (static) decision-making rules used to exercise the call options. We assume that call options are not exercised unless natural gas prices exceed the strike price by a fixed threshold,[48] based on analysis of historical data. With more complex decision-making rules for determining when to exercise call options, where this threshold varies based on the number of remaining calls and expected market conditions, the contract could potentially earn higher returns than those presented in **Table 15**. For example, the contract holder earns no returns in the Infrequent Case, although relaxing the threshold prices for exercising the call options could provide the holder with some gains from the contract.

A second issue is that our analysis does not capture the gains from reduction in financial risk under certain market conditions. In particular, while the analysis captures the gains from reductions in risk when natural gas prices are relatively high (e.g., exceeding the LNG price) and the resource sells DA energy, it does not account for risk benefits when prices are relatively low (e.g., less than the LNG price), where the resource sells DA energy options. More specifically, a forward LNG contract would cover intra-day fuel price risk for a gas-only facility awarded a DA energy option on a day when natural gas prices are relatively low. Without the forward

[47] In aggregate, the forward LNG contract would be expected to increase gas-only DA energy supply, as some oil-fired generation is displaced by gas-only generation. But, many factors potentially affect which resources earn those incremental FER payments, including the efficiency (heat rate) of the unit with the forward LNG contract, the portfolio of resources owned by the contract-holder, and other market trading arrangements available through which the contract-holder could earn a premium on the sale of its natural gas supply.

[48] The analysis assumes a static threshold for exercising the call options ($16 per MMBtu) that is above the commodity price ($10 per MMBtu). The higher threshold for exercising the call option accounts for the opportunity cost to exercising one of the limited number of call options. It ensures that the owner does not exercise the call to earn a small return, thus precluding a potential future return of higher magnitude. This threshold was calculated using quantitative analysis of historical New England market conditions.

LNG contract, the unit selling the option would face the risk that real-time energy and gas prices would increase dramatically the next day. Because the strike price would remain in line with the lower DA LMP, an increase in the resource's marginal costs due to the higher real-time gas price would leave the resource owner exposed to the risk of large losses. A forward LNG contract would help mitigate this risk, a benefit that is not captured quantitatively. As a result, the analysis presented may understate ESI's impact on resource incentives to enter into such forward LNG contracts.

Under current market rules, there may be a gap between prices a generator and LNG terminal are willing to accept for a forward LNG contract. Prior work estimated this gap to be $2,705 per MW in the context of establishing a compensation rate for the Interim Program.[49] This analysis did not attempt to account for the heterogeneity in this gap among market participants. In practice, the magnitude of this gap likely varies across market participants, with some higher and others lower than this estimate. For example, some market participants have entered into forward LNG contracts in recent winters, implying there is no gap for their resources under current market rules and conditions.

Incremental ESI revenues may close whatever gap there is between additional generators and the region's LNG terminals to reaching agreement. In the Frequent and Extended Cases, incremental ESI revenues are of the same order of magnitude as the amount that was estimated to be necessary to incent LNG contracting in the context of the Interim Program. That is, the incremental revenues are $2,066 per MW in the Frequent Case and $1,511 per MW in the Extended Case, as compared to an estimated gap of $2,705 per MW. Thus, these incremental revenue streams due to ESI would potentially incent some resources toward entering into such contracts that they otherwise would not enter into.

2. Supply of Energy and DA Energy Options

The ESI proposal is expected to result in multiple changes to day-ahead and real-time energy supply, including changes in the supply of energy (clearing in the day-ahead market), shifts in the composition of resources supplying energy in both day-ahead and real-time markets, and a new supply of DA energy options that are not procured under current market rules.

Historically, the supply of physical energy clearing in the day-ahead markets has been less than the ISO-NE load forecast, on average. **Table 16** compares the quantity of cleared physical DA energy to the ISO-NE load forecast in our winter CMR Cases, which is based on historical cleared DA energy and load forecasts. Under current market rules, when the day-ahead market clears physical energy supplies below the ISO-NE load forecast, resources in the market implicitly supply load with an option to provide additional energy needed to meet load in real-time. This option is exercised through a variety of means, including supplemental reliability commitments by ISO-NE after the day-ahead market has cleared. These supplemental commitments may cause additional resources to be committed if the reliability analysis determines that the additional energy that can be provided from the resources cleared in the day-ahead market or that can quickly come online are not sufficient to meet ISO-NE's load forecast. Even if additional units are not committed, reliability may be maintained through the ramp capability of units that clear a portion of their operating capacity in the day-ahead

[49] Analysis performed in the context of analysis performed for the interim inventories energy program. *See* Testimony of Todd Schatzki, Federal Energy Regulatory Commission, Docket No. ER19-1428-000.

market or through the reliance on fast start resources. These services are presently uncompensated, and as a result, the financial incentives for such resources, which ISO-NE is implicitly counting on to meet its reliability needs, to take the necessary actions to be available if called may not be consistent with the services they provide.

Table 16. Percent of Hours with Cleared Supply Less than Forecast Load, Winter CMR Case

	Cleared DA Energy Supply < ISO Forecast Load	
CMR Case	**Share of Hours (%)**	**Average Difference (MW)**
Frequent Case	92%	519
Extended Case	64%	334
Infrequent Case	81%	383

Note: The load forecast depicted in the table is the forecast available prior to clearing the day-ahead market, at around 9:30am on OD-1.

An important element of the ESI design is the increase in cleared DA energy caused by the co-optimization of the DA energy and EIR awards, and the expected increase in day-ahead bid-in demand. **Section III.B.5** described these adjustments in greater detail. In short, with ESI, social surplus may be maximized by buying more DA energy to reduce the gap between cleared DA energy and the forecast load, and thereby limiting the quantity of EIR that is procured to satisfy the FER. Day-ahead bid-in demand increases to eliminate arbitrage opportunities between the day-ahead and real-time markets, which further reduces the gap between cleared DA energy and the forecast load.

Table 17 shows the changes in cleared DA energy by resource type between CMR and ESI during the winter Central Cases. Under CMR, the total energy clearing in the day-ahead market ranges from 31.0 to 31.5 TWh across Cases (column [A]). By contrast, under ESI, total cleared DA energy ranges from 31.6 to 32.2 TWh (column [B]), representing an increase of 0.4 to 1.0 TWh of DA energy supply. Thus, ESI leads to increases of 1.4% to 3.3% in DA energy compared to current market rules.[50]

Table 17. Changes in Cleared DA Energy, Winter Central Case
CMR vs ESI (MWh)

	CMR	ESI		Difference	Real-Time Comparison	
Case	**Day-Ahead Energy [A]**	**Day-Ahead Energy [B]**	**Cleared EIR [C]**	**Day-Ahead Energy [D] = [B] - [A]**	**Real-Time Demand**	**Energy + EIR [E] = [B] + [C]**
Frequent Case	31,188,025	32,215,469	6,604	1,027,443	32,155,711	32,222,073
Extended Case	31,503,187	31,943,398	25,172	440,211	31,840,458	31,968,570
Infrequent Case	31,047,336	31,634,655	83,245	587,318	31,525,206	31,717,899

50 Note that, under ESI, the sum of DA energy and EIR across the winter exceeds the real-time energy demand in each of the Cases. This occurs because, while ESI generally avoids under-procurement day-ahead by procuring DA energy and EIR to cover the forecast load, it does not prevent the day-ahead market from clearing more physical energy than the load forecast, which can occur for a variety of reasons, including risk hedging and price expectations.

Table 18 provides the total quantity of DA energy and DA energy options procured in each Central Case. In total, 7.7 to 7.9 GW of DA energy options are procured across the three Cases. The vast majority of these DA energy options are procured for GCR and RER. The quantity of RER procured in the Frequent and Extended Cases is less than the maximum quantity because, in some hours, procuring the full requirement (1,200 MW) is either infeasible or would require substitutions with (marginal) costs greater than the RER penalty factor value ($100 per MWh). Thus, in these hours, the market procures a quantity of DA energy options less than the RER requirement rather undertake additional purchases that would cause the RER price to rise above the RER penalty factor value.

Table 18. Cleared DA Energy and Ancillary Service Products, Winter Central Case, ESI (MWh)

		DA Energy Options				
Case	**Day-Ahead Energy**	**Total**	**EIR**	**GCR10**	**GCR30**	**RER**
Frequent Case	32,215,469	7,749,058	6,604	3,456,000	1,728,000	2,558,454
Extended Case	31,943,398	7,791,810	25,172	3,456,000	1,728,000	2,582,638
Infrequent Case	31,634,655	7,859,245	83,245	3,456,000	1,728,000	2,592,000

Note: The quantity of GCR30 reflects the nested GCR30 quantity, incremental to the GCR10 quantity, not the total GCR30 requirement. The RER quantity reflects the total quantity of DA energy options procured, exclusive of amounts not procured because RER prices are constrained by the penalty factor.

The increases in DA energy occur during hours when the energy supply clearing in the day-ahead market would be less than the ISO-NE load forecast under current market rules. However, the substitution of DA energy for EIR does not completely eliminate the gap between cleared DA energy and the ISO-NE load forecast.[51] For each Case, column [C] shows the quantity of cleared EIR, which ranges from 6.6 to 83.2 GWh. Thus, the EIR quantity is small compared to the difference in DA energy under CMR and ESI, indicating that ESI is expected to reduce the gap between cleared DA energy supply and the ISO-NE load forecast that exists under the current market rules.

Compared to current market rules, ESI leads to a shift in the supply of DA energy across resource types. **Table 19** to **Table 21** show the impact of ESI on the products supplied in the day-ahead markets across resource types. Because of the increase in total DA energy caused by ESI, most resources increase the supply of DA energy, with the largest increases for combined cycle units (dual-fuel and gas-only), oil-only steam units and dual-fuel combustion turbines.

DA energy options are supplied by a mix of resources, including (in order of quantity supplied) pumped storage, combustion turbines (all fuel types), hydro power and combined cycle units (dual fuel and gas-only). For some of these resource types, under ESI, DA energy options become a large share of the services provided in the day-ahead market. At one extreme, oil-only non-steam combustion turbine units supply about 10 times the amount of DA energy options compared to DA energy. Pumped storage and dual fuel combustion turbines

[51] In these hours, procuring additional DA energy options to provide EIR results in greater social surplus than clearing additional DA energy. More specifically, the costs associated with procuring these options is less than the social surplus loss associated with procuring more DA energy (i.e., the difference in price between incremental demand bids and supply offers).

also supply similarly large fractions of DA energy options relative to DA energy. At the other extreme, combined cycle units (gas-only and dual fuel) supply about 10 times the amount of DA energy relative to DA energy options. Thus, the cost-effective allocation of DA energy and DA energy options considers both the cost of supplying energy – with the lowest marginal cost resources generally selected – and the cost of supplying DA energy options.

There is some substitution between DA energy and DA energy options for some resource types. For example, although total DA energy increases under ESI relative to CMR, supply from oil-only combustion turbines decreases. However, this decrease is offset by a large supply of DA energy options provided by these resources. For example, in the Frequent Case, DA energy from oil-only combustion turbines decreases by 29,182 MWh (more than a 10% decrease), while these resources sell 2.0 TWh of DA energy options.

Table 19. Energy and DA Energy Options by Resource Type
CMR vs ESI, Winter Central Frequent Case (MWh)

Resource Type	Winter SCC Capacity (MW)	DA CMR Energy (MWh)	DA ESI Energy (MWh)	DA Energy Options (MWh)	Change in DA Energy (MWh)
Active Demand Response	285	18,559	18,810	0	251
Battery Storage	458	41,206	41,206	0	0
Biomass/Refuse	849	1,601,428	1,601,638	0	211
Coal	535	957,230	964,935	10,540	7,705
Dual Fuel - CC	6,392	5,887,192	6,225,924	414,403	338,733
Dual Fuel - CT	1,435	697,219	739,743	1,297,907	42,525
Fuel Cell	21	35,109	35,123	0	15
Gas - CC	7,583	3,131,703	3,467,244	405,473	335,541
Gas - CT	404	669	704	280,643	35
Gas with LNG under ESI	616	1,020,701	1,076,091	67,815	55,390
Hydro	1,987	1,251,996	1,251,996	790,887	0
Imports	2,850	6,096,019	6,099,641	0	3,622
Nuclear	3,344	7,184,403	7,184,403	0	0
Offshore Wind	800	879,483	879,483	0	0
Oil Only - Steam	3,792	1,290,766	1,560,537	217,653	269,771
Oil Only - CT	2,511	194,309	165,127	2,003,399	(29,182)
Pumped Storage	1,778	616,108	616,108	2,251,837	0
Solar	1,671	152,197	152,197	0	0
Wind	1,401	992,964	992,964	0	0

Note: (1) DA energy for battery storage and pumped storage reflect (on-peak) discharged supply, and is not net of (off-peak) charging withdrawals.
(2) Oil Only - CT is largely combustion turbine units, but also include internal combustion engines.

Table 20. Energy and DA Energy Options by Resource Type
CMR vs ESI, Winter Central Extended Case (MWh)

Resource Type	Winter SCC Capacity (MW)	DA CMR Energy (MWh)	DA ESI Energy (MWh)	DA Energy Options (MWh)	Change in DA Energy (MWh)
Active Demand Response	285	23,846	11,850	0	(11,996)
Battery Storage	458	41,206	41,206	0	0
Biomass/Refuse	849	1,581,343	1,577,716	0	(3,627)
Coal	535	646,721	652,128	9,048	5,406
Dual Fuel - CC	6,392	5,416,572	5,618,953	397,252	202,381
Dual Fuel - CT	1,435	470,553	494,509	1,428,271	23,956
Fuel Cell	21	23,202	23,316	0	115
Gas - CC	7,583	4,729,551	4,933,753	264,301	204,202
Gas - CT	404	0	0	304,397	0
Gas with LNG under ESI	616	1,242,134	1,287,505	34	45,372
Hydro	1,987	1,526,266	1,526,266	1,123,614	0
Imports	2,850	5,929,432	5,931,763	0	2,331
Nuclear	3,344	7,184,403	7,184,403	0	0
Offshore Wind	800	879,483	879,483	0	0
Oil Only - Steam	3,792	619,222	641,855	35,773	22,634
Oil Only - CT	2,511	116,800	64,788	1,148,060	(52,012)
Pumped Storage	1,778	616,108	616,108	3,080,047	0
Solar	1,671	245,603	245,603	0	0
Wind	1,401	1,083,132	1,083,132	0	0

Note: See note for **Table 19**.

Table 21. Energy and DA Energy Options by Resource Type
CMR vs ESI, Winter Central Infrequent Case (MWh)

Resource Type	Winter SCC Capacity (MW)	DA CMR Energy (MWh)	DA ESI Energy (MWh)	DA Energy Options (MWh)	Change in DA Energy (MWh)
Active Demand Response	285	4,246	4,380	0	134
Battery Storage	458	41,206	41,206	0	0
Biomass/Refuse	849	1,559,242	1,559,753	0	510
Coal	535	549,273	558,894	15,725	9,621
Dual Fuel - CC	6,392	5,170,503	5,443,353	357,917	272,850
Dual Fuel - CT	1,435	362,534	362,669	1,526,744	135
Fuel Cell	21	12,645	13,162	0	517
Gas - CC	7,583	5,543,212	5,830,502	291,525	287,290
Gas - CT	404	74	74	393,496	0
Gas with LNG under ESI	616	1,316,801	1,316,801	0	0
Hydro	1,987	1,421,185	1,421,185	1,137,865	0
Imports	2,850	5,850,967	5,856,778	0	5,811
Nuclear	3,344	7,184,403	7,184,403	0	0
Offshore Wind	800	931,752	931,752	0	0
Oil Only - Steam	3,792	51,739	61,149	2,058	9,410
Oil Only - CT	2,511	2,553	3,556	1,324,243	1,003
Pumped Storage	1,778	616,108	616,108	2,809,637	0
Solar	1,671	289,960	289,960	0	0
Wind	1,401	1,017,230	1,017,230	0	0

Note: See note for **Table 19**.

The mix of energy supply varies across time with changes in market conditions, including load levels, natural gas supply available to the electricity sector (given weather-related variation in LDC natural gas demand), and the available natural gas supplies, which when tight, may cause a drawdown in energy inventories. **Figure 22** illustrates the hourly cleared supply of DA energy by technology type in the Frequent Case. The figure illustrates the shifts in supply that occur during periods of tight natural gas supplies, where awards to generators using oil (dual fuel is purple, oil-only is black) are generally increasing compared with periods with less stressed market conditions because of the energy inventories upon which these resources can draw.

Figure 22. Hourly Cleared DA Energy by Resource Type

ESI, Winter Central Frequent Case (MWh)

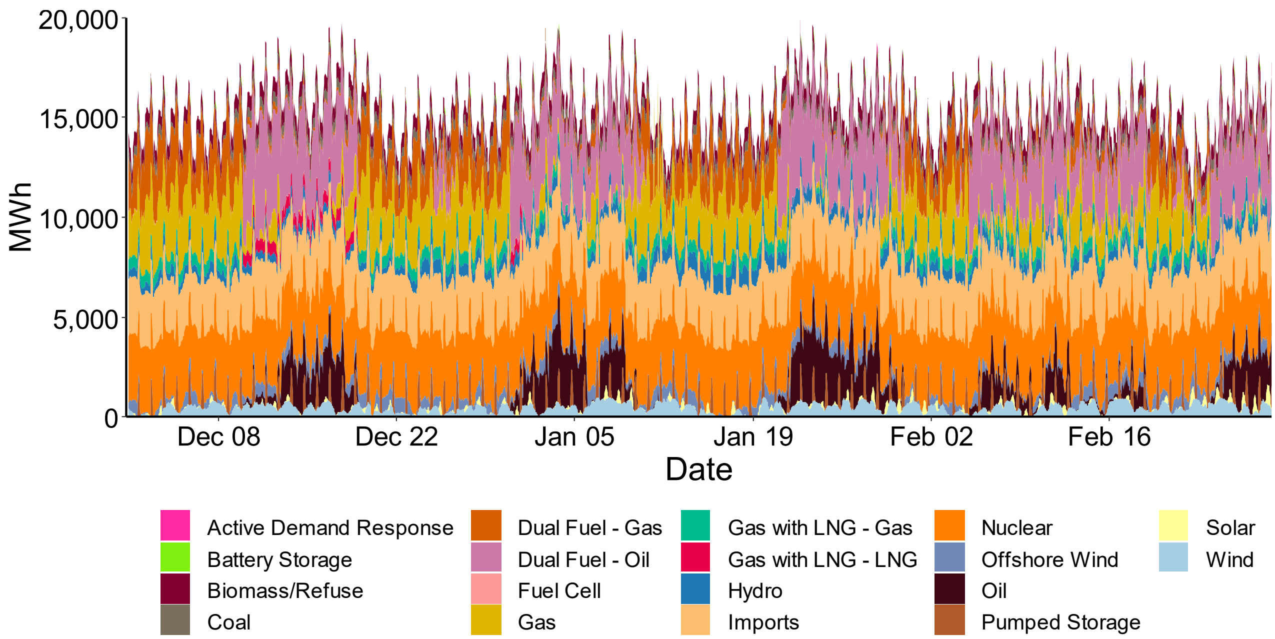
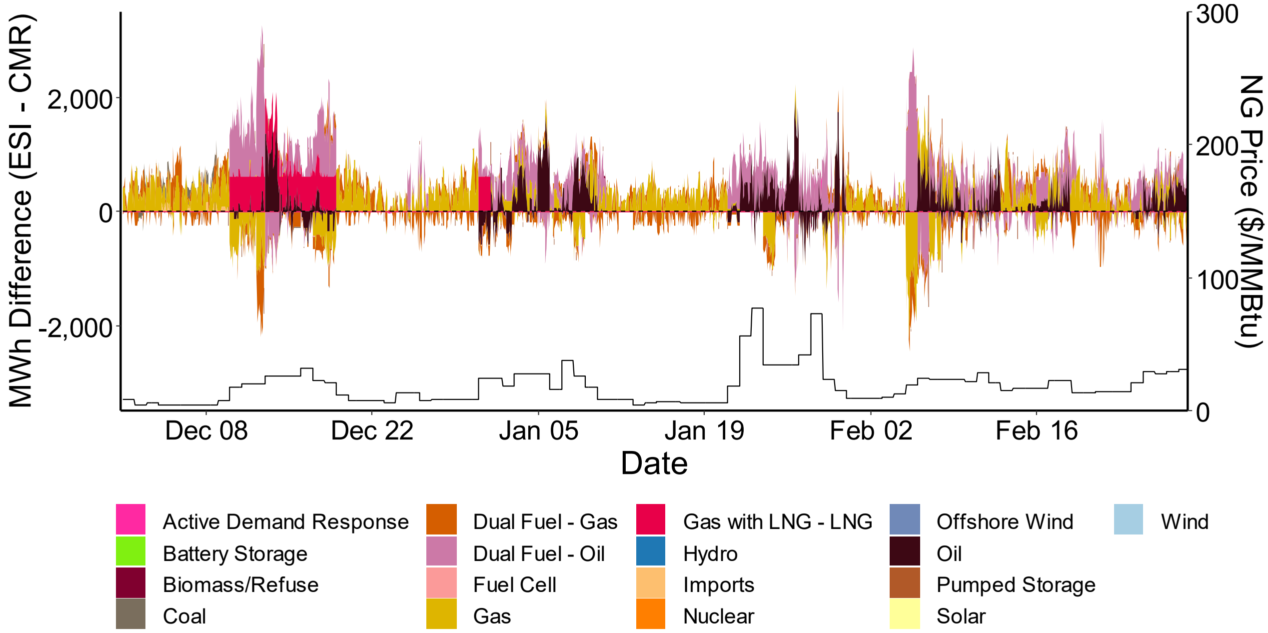


Figure 23 shows the mix of resources that make up differences in cleared DA energy between CMR and ESI in each hour in the Frequent Case. In each hour, the difference in DA energy supply reflects increases by some resources (shown by amounts greater than zero) and decreases by others (shown by amounts less than zero). As discussed above, in each hour, the quantity of DA energy increases under ESI compared to CMR. But, the figure shows that this increase in energy can reflect added supply from some resources, and a decrease in supply by others. For example, between December 9 and December 18, DA energy increases from oil-fired dual fuel and gas-fired units supported by a forward LNG contract, while DA energy decreases from gas-only resources (relying on pipeline natural gas), as this period corresponded with high pipeline gas prices. The figure illustrates the range of substitutions that occur between the CMR and ESI cases given the many dynamic factors captured by the model. These shifts in supply among resource types are largest during periods when the natural gas price is high (as shown by the lower line, right-hand y-axis). Thus, the figure illustrates how the impact of ESI on resource use is greatest during periods of system stress, given the greater

incremental energy inventory under ESI and substitution of supply (DA energy and DA energy options) among different technology types.

Figure 23. Difference in Hourly Cleared DA Energy by Resource Type
CMR vs ESI, Winter Central Frequent Case



3. *Production Costs*

Production costs are a commonly used metric for evaluating the social costs of producing goods and services. As such, changes in production costs can signal how policy or regulatory proposals affect a market's efficiency, and we use this metric to assess whether ESI appears likely to reduce the costs to meeting electricity demand. While our evaluation of production costs appropriately captures the social cost of the physical resources used by generators to meet customer loads, it may not encompass all social costs and benefits. For example, production costs may not capture certain financial costs and changes in utility, although capturing these effects would be very challenging and beyond the scope of our analysis.[52]

The ESI proposal would be expected to lower total production costs incurred to meet real-time loads through multiple effects, including the additional energy inventory incented by ESI, the shifts in energy supply through changes in energy inventory use, and the more efficient unit commitment to meet real-time operating reserves. These additional fuel supplies would be expected as a result of new incentives from ESI for resources to increase energy inventories and otherwise increase the ability of resources to deliver energy supply in real-time (e.g., through general improvements in operational performance). With larger

[52] ESI may cause a range of effects to financial cost and underlying utility of consumers. The procurement of DA energy options, for example, may impose financial costs if it causes changes to market participant's financial structures to account for changes in financial risk. However, accounting for these costs would be extremely complex, particularly given the potential for ESI to have spillover effects on other market operations.

energy inventories (and better resource performance), the cost of meeting real-time loads would be reduced, particularly during periods of tight fuel supply when the market would otherwise require that load be met through more costly generation resources. These reductions in production costs are consistent with an increase in market efficiency, reflecting actions to improve energy deliverability in tight market conditions, rather than the underinvestment in energy security that can occur under current market rules, identified as the "misaligned incentives" problem in the ESI White Paper. ESI would also be expected to change production costs in other ways that are not fully captured in our model, notably through more efficient unit commitment to meet real-time operating reserves. As a result, these results may understate any reductions in production costs that ESI produces.

Table 22 shows the estimated change in total production costs. The estimate of total production costs includes the marginal cost of production, including fuel and variable costs.[53] For example, in the Frequent Case, total model production costs are $1.42 billion under CMR and $1.37 billion under ESI, resulting in a $40.7 million reduction in model production costs. Under ESI, the quantity of energy held in inventory at the end of the winter season is greater than under CMR. The estimated change in cost of holding this fuel until the beginning of the next winter season is $5.3 million. Netting these holding costs from the $40.7 million reduction in production costs of supplying energy to load results in a change in total production costs of $35.5 million. Results are similar in the Extended Case, with total production costs reduced by an estimated $19.3 million, reflecting a reduction in model production costs of $25.0 million and an increase in holding costs of $5.7 million.

Table 22. Difference in Production Costs, Winter Central Case
CMR vs ESI ($ Million)

Case	Total Model Production Costs [1] ($ Million)			Incremental Energy Inventory Costs with ESI [2] ($ Million)	Change in Total Production Costs ($ Million)
	CMR	ESI	Change		
Frequent Case	$1,415.1	$1,374.4	($40.7)	$5.3	($35.5)
Extended Case	$939.5	$914.5	($25.0)	$5.7	($19.3)
Infrequent Case	$657.2	$656.3	($0.9)	$8.5	$7.5

Notes:
[1] Production costs only do not include opportunity costs.
[2] Incremental energy inventory costs include LNG and oil holding costs for incremental fuel at the end of the winter.

In contrast to the Frequent and Extended Cases, costs increase in the Infrequent Case by $7.5 million, reflecting a $0.9 million reduction in total model production costs and an increase in energy inventory holding costs of $8.5 million. Thus, these results suggest that ESI may not lower production costs under all market conditions.

These results show that ESI operates in a manner similar to insurance with respect to total economic costs. Similar to insurance, ESI would be expected to increase energy inventory, providing increased economic

[53] Estimated production costs exclude costs associated with nuclear, pumped storage, hydropower, wind power and solar, which are unchanged between the CMR and ESI model runs.

"protection" that lowers costs during periods of tight market conditions. However, similar to insurance, the cost of this protection may not always produce benefits that outweigh the costs, especially during "mild" conditions.

4. Emissions

Shifts in the mix of energy supply caused by ESI would lead to corresponding changes in total emissions given differences in the emission rates of individual resources in the fleet. **Table 23** shows the change in emissions between CMR and ESI for each of the Central Cases. Estimates of changes in total emissions reflect resource-specific emission rates and shifts in RT energy supply between resources. Emissions increase in some cases, and decrease in others. For example, carbon dioxide and sulfur dioxide emissions decrease in two of three cases. By contrast, oxides of nitrogen emissions increase in all three cases.

Table 23. Difference in Emissions, CMR vs ESI, Winter Central Case

	Total					
Case	**CO_2 (lbs)**		**SO_2 (lbs)**		**NO_X (lbs)**	
Frequent Case	124,298,774	0.63%	211,494	1.45%	1,372,155	4.44%
Extended Case	(53,987,006)	-0.31%	(109,636)	-1.26%	197,090	1.10%
Infrequent Case	(5,232,664)	-0.03%	(5,551)	-0.09%	19,985	0.17%

The primary driver of these changes in total emissions are the shifts in energy supply across various technology types. As described in **Section IV.2**, the shifts in energy supply due to ESI are quite complex. Moreover, even within technology types, emission rates are not uniform across units due to differences in generation efficiency (heat rates) and pollution control equipment (i.e., emissions per MMBtu fuel consumed). **Table 24** provides the change in total fuel consumption under ESI (compared to CMR) for each Central Case.

Table 24. Difference in Fuel Consumption by Fuel Type, CMR vs ESI, Winter Central Case

	Total					
Case	**Natural Gas (MMBTU)**		**Oil (BBL)**		**Coal (MMBTU)**	
Frequent Case	(2,053,357)	-4.21%	303,106	3.59%	-	0.00%
Extended Case	(30,051)	-0.04%	(68,471)	-1.74%	-	0.00%
Infrequent Case	-	0.00%	(4,752)	-0.36%	-	0.00%

5. Customer Payments

Total change in customer payments due to the ESI proposal will reflect a combination of factors:

- ***First, total LMP payments through day-ahead and real-time markets will shift due to a combination of factors.*** Several factors put downward pressure on LMPs, which will tend to reduce consumer costs. These factors include the increased supply of energy in inventory due to ESI's incentives to secure increased energy inventory, and the increase in supply of energy clearing the day-ahead market given the substitution of DA energy for EIR (which *lowers* LMPs because the DA LMP is generally set based on the offer price of the marginal bid-in demand). On the other hand, the shift in the energy mix due to various intra-hour and inter-hour substitutions within the market could increase LMPs.

- ***Second, resources supplying DA energy will receive FER payments as compensation for contributions to meeting the FER.*** This will tend to increase consumer payments.
- ***Third, consumers will make new payments to procure energy options in the day-ahead market.*** When RT LMPs are above the strike prices, load will be credited for the settlement of these options, equal to this price difference. This real-time settlement will partially offset the day-ahead payments for the options, but to the extent that participants include a risk component in their offer price, this closeout settlement is unlikely to fully offset the day-ahead payment, on average.

Table 25 summarizes the net impact of these three components on total customer payments. In the Infrequent Case, payments increase by $35 million over the 3-month winter (a 2.0% increase), reflecting an increase in payments to energy of $20 million (reflecting a $41 million reduction associated with decreased LMPs and a $61 million increase in payment due to FER payments) and net payments of $15 million for DA energy options.

Total payments both increase and decrease in the stressed conditions cases. In the Frequent Case, payments increase by $132 million (a 3.2% increase), reflecting a decrease in LMP payments of $183 million, FER payments of $250 million and net DA energy option payments of $66 million. In the Extended Case, however, payments decrease by $69 million (a 2.5% decrease), reflecting a decrease in LMP payments of $214 million, FER payments of $113 million and net DA energy option payments of $32 million.

Table 25. Total Payments, Winter Central Case ($ Million)

		Frequent Case				Extended Case				Infrequent Case			
Product / Payment		**CMR**	**ESI**	**Difference**		**CMR**	**ESI**	**Difference**		**CMR**	**ESI**	**Difference**	
Energy and RT Operating Reserves	[A]	$4,101	$3,917	-$183	-4.5%	$2,730	$2,516	-$214	-7.8%	$1,749	$1,707	-$41	-2.4%
DA Energy Option													
DA Option Payment			$207				$113				$45		
EIR			$0				$1				$1		
RER			$67				$37				$15		
GCR10			$93				$50				$20		
GCR30			$47				$25				$10		
RT Option Settlement			-$142				-$81				-$31		
Net DA Ancillary	[B]		$66				$32				$15		
FER Payments	[C]		$250				$113				$61		
Total Payments	[A+B+C]	$4,101	$4,233	$132	3.2%	$2,730	$2,661	-$69	-2.5%	$1,749	$1,783	$35	2.0%

The aggregate totals in **Table 25** mask hourly variation in these impacts across the winter. This hourly variability is particularly important for the new ESI products, given the novel settlement structure of the new energy options commodity. Payments for the ESI products reflect both upfront payments for the DA energy options and settlement of the options, which provides offsetting compensation to load. **Figure 24** to **Figure 26** shows these net effects at the hourly level to illustrate the variability in net impacts. More specifically, **Figure 24** shows the upfront payments for the DA energy options in each hour over a 14-day period. These payments are generally in the range of $40,000 to $140,000 per hour and remain relatively stable across hours, suggesting that before the day-ahead market is run, option sellers may have similar expectations about potential closeout costs across hours.

Figure 24. Hourly DA Energy Option Payments
All ESI Products, Winter Central Frequent Case, Jan 8 to Jan 22 ($ Thousands)

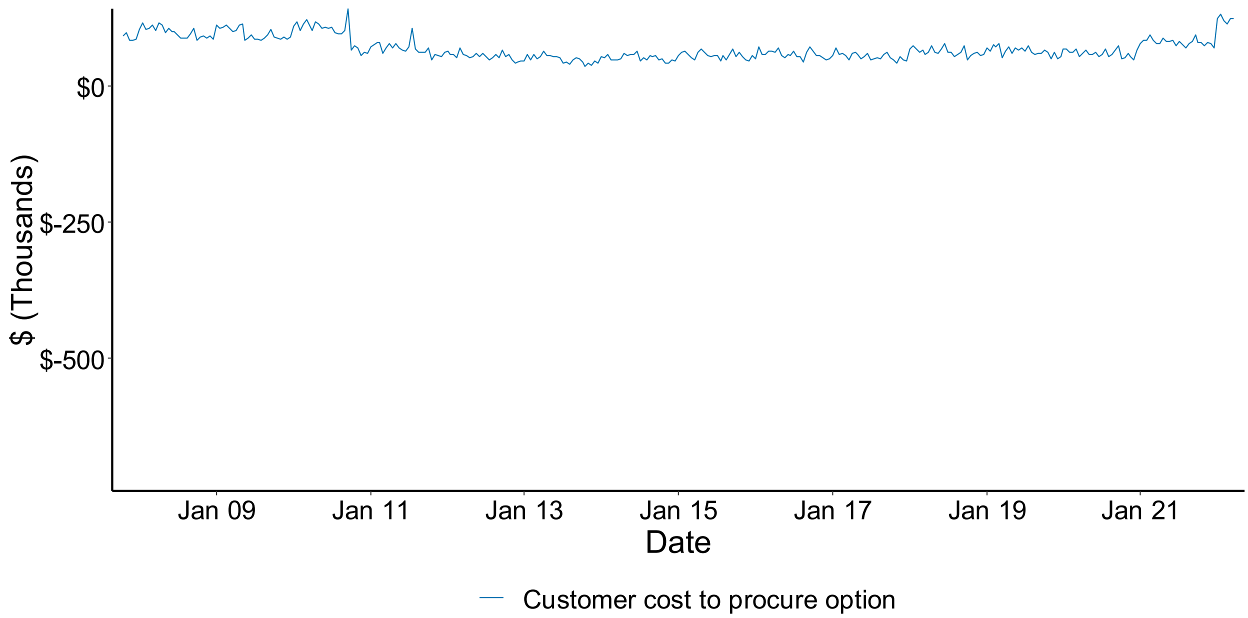


Figure 25 includes the same payments as **Figure 24**, and adds the real-time settlement of the options, which has the opposite sign, as it represents a charge to generation and a rebate to load. This value is $0 in many hours, indicating that the RT LMP is less than or equal to the strike price, and the option closeout cost is $0. However, in some hours, this closeout cost is significant as the RT LMP exceeds the strike price by some margin, suggesting that while sellers may have expected similar closeout costs across hours, they varied significantly.

Figure 25. Hourly DA Energy Option Payments and RT Option Settlement
All ESI Products, Winter Central Frequent Case, Jan 8 to Jan 22 ($ Thousands)

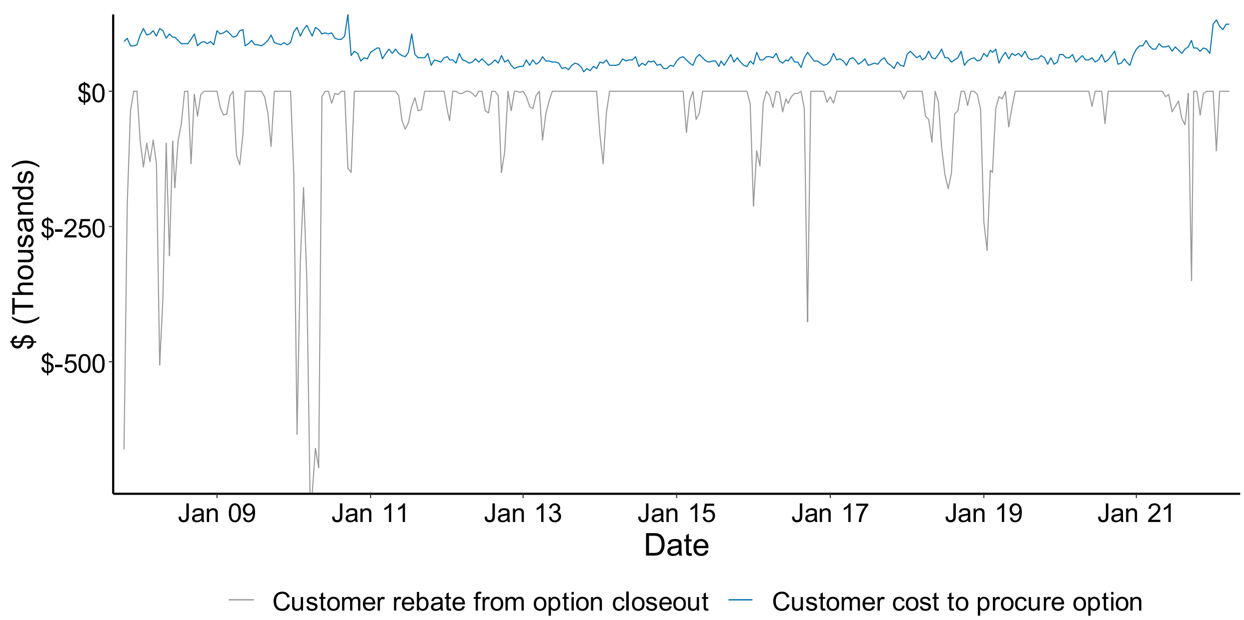


Figure 26 includes both the initial costs to procure the options and the settlement, and adds the total option costs, equal to this initial cost less the closeout. As the figure illustrates, the net cost to consumers is positive in many hours, but it also results in a net rebate in some hours, as the settlement rebate exceeds the initial cost to procure the option.

Figure 26. Hourly DA Energy Option Payments, RT Option Settlement and Net Payments
All ESI Products, Winter Central Frequent Case, Jan 8 to Jan 22 ($ Thousands)

6. Resource Net Revenues

The impact of ESI on the net revenues earned by resources participating in the New England energy markets depends on a combination of factors. In aggregate, changes in payments by load will lead to corresponding changes in revenues to generators. Thus, in Cases when payments by load are expected to increase, this would be expected to lead to a corresponding increase in revenues to resource owners.

Table 26 to **Table 28** provide the average net revenues by resource type for the Frequent, Extended and Infrequent Cases, respectively.[54] Unlike the analysis of incentives for energy inventory, the change in net revenues accounts not only for the additional FER payments and DA energy option net revenues, but also reductions in LMPs caused by the larger energy inventories.[55] With a few exceptions, net revenues increase

[54] **Table 26** to **Table 28** do not include certain technology types, when our modeling of the resource dispatch is not sufficiently detailed to accurately characterize expected impacts. For example, output (and charging load) for battery and pumped storage reflect historical profiles, not economic offers, and thus may not accurately capture resource responses to ESI.

[55] For the purposes of evaluating net revenues, we consider all changes in payments, including any reductions in LMPs that would occur due to increases in energy inventories in response to ESI's incentives. While it is sensible to include these effects when evaluating net revenues, when evaluating ESI's incentives to improve delivery of energy in real-time, we focus on the direct incentives created by ESI, while acknowledging that this indirect effect on LMPs may dampen the magnitude of the response to these incentives.

for each resource type in Cases when payments by load are greater (i.e., the Frequent and Infrequent Cases), and net revenues decrease for each resource type in Cases when payments by load are lower (i.e., the Extended Case). However, the magnitude of these changes varies across resources. These differences depend on a variety of factors, including resource-specific operational characteristics, such as plant operating efficiency, fuel costs and fuel inventory.

Table 26. Average Net Revenues by Resource Type, Winter Central Frequent Case
($ per MW–3-Month Winter)

	Net Revenue ($/MW Capacity)		
Resource Type:	**CMR [A]**	**ESI [B]**	**Change [C] = [B] - [A]**
Dual Fuel - CC	$38,260	$42,210	$3,950
Dual Fuel - CT	$19,548	$30,244	$10,696
Gas Only - CC	$2,231	$3,273	$1,042
Gas Only - CT	$188	$6,107	$5,919
Gas with LNG under ESI	$13,244	$17,416	$4,172
Oil Only - Steam	$10,174	$14,839	$4,665
Oil Only - CT	$2,435	$8,664	$6,228
Coal	$161,951	$165,483	$3,532
Biomass/Refuse	$229,680	$233,026	$3,346
Fuel Cell	$144,742	$147,890	$3,148
Hydro	$95,745	$100,113	$4,368
Nuclear	$268,661	$272,340	$3,679
Solar	$12,222	$12,239	$17
Wind	$94,529	$95,750	$1,221
Offshore Wind	$138,457	$139,966	$1,509

Table 27. Average Net Revenues by Resource Type, Winter Central Extended Case
($ per MW–3-Month Winter)

	Net Revenue ($/MW Capacity)		
Resource Type:	**CMR [A]**	**ESI [B]**	**Change [C] = [B] - [A]**
Dual Fuel - CC	$20,343	$18,298	($2,046)
Dual Fuel - CT	$13,555	$17,046	$3,491
Gas Only - CC	$6,257	$6,750	$494
Gas Only - CT	$0	$2,813	$2,813
Gas with LNG under ESI	$27,299	$26,965	($334)
Oil Only - Steam	$9,748	$5,283	($4,465)
Oil Only - CT	$3,964	$2,360	($1,604)
Coal	$87,783	$82,474	($5,309)
Biomass/Refuse	$148,791	$143,160	($5,632)
Fuel Cell	$76,588	$71,216	($5,373)
Hydro	$66,814	$67,193	$380
Nuclear	$175,308	$169,440	($5,869)
Solar	$9,944	$9,638	($307)
Wind	$68,604	$64,961	($3,644)
Offshore Wind	$93,357	$89,652	($3,705)

Table 28. Average Net Revenues by Resource Type, Winter Central Infrequent Case
($ per MW–3-Month Winter)

	Net Revenue ($/MW Capacity)		
Resource Type:	**CMR [A]**	**ESI [B]**	**Change [C] = [B] - [A]**
Dual Fuel - CC	$6,594	$7,102	$508
Dual Fuel - CT	$6,070	$7,697	$1,627
Gas Only - CC	$7,702	$8,355	$653
Gas Only - CT	$21	$1,573	$1,552
Gas with LNG under ESI	$27,668	$7,348	($20,320)
Oil Only - Steam	$310	($973)	($1,283)
Oil Only - CT	$1	$752	$751
Coal	$34,234	$35,184	$950
Biomass/Refuse	$96,287	$97,453	$1,165
Fuel Cell	$27,541	$28,023	$482
Hydro	$39,673	$41,168	$1,495
Nuclear	$115,752	$117,111	$1,359
Solar	$7,707	$7,761	$54
Wind	$38,893	$39,309	$415
Offshore Wind	$60,976	$61,702	$726

7. *Operational Impacts and Reliability*

The proposed ESI market rules are expected to improve system reliability by procuring day-ahead services that ensure the system has energy supplies available to meet real-time operational needs. As described in **Section I.B**,[56] each of the ESI option products is designed to ensure that energy supplies are available to fill potential gaps in energy supplies and improve the region's energy security. More specifically, these option products will help to ensure that forecast loads can be met in real-time (EIR), operating reserves have sufficient energy supplies to respond to system contingencies (GCR), and energy supplies are available to replace the operating reserves when they are deployed to respond to extended, large contingencies (RER). Procuring these services will create incentives for resources to take actions along short-term and long-term horizons to improve their ability to provide real-time energy supplies.

As noted previously, our production cost model is not designed to provide a thorough or complete analysis of the impact of ESI on potential reliability outcomes. Such impacts are typically performed through other modeling techniques and may reflect different assumptions about a variety of factors that would impact reliability and security outcomes. The model does not consider a complex set of contingency events, does not account for transmission topology, and does not consider plant commitment, dispatch and other intertemporal limits to plant operations (e.g., minimum run time and minimum down time). Due to the combined impact of these factors, we would expect our model to understate potential reliability risks associated with any market simulation under both the CMR and ESI runs. As a result, to the extent that the incremental energy inventories that ESI may incent improve the region's reliability, these benefits are likely to be understated.

Nonetheless, we analyze multiple metrics that can provide information consistent with reliability improvements. These metrics include traditional reliability metrics associated with resource availability. But, they also include a broader set of metrics related to fuel use and fuel inventory, as these are related to ESI's objectives of securing energy supplies. In particular, we evaluate:

- ***Operating reserve shortages:*** Hours of 10- or 30-minute operating reserve shortage.
- ***Natural gas consumption when natural gas supply is tight:*** Change in natural gas consumption during periods when the natural gas supply is tight, as reflected by high prices (greater than $16 per MMBtu). This metric provides information on the extent to which ESI relaxes pressure on fuel supply systems during stressed conditions when gas prices are high. This quantity is estimated net of natural gas supply from forward LNG contracts.
- ***Minimum and average daily quantity of deliverable energy from oil-fired units.*** The quantity of energy (MWh) available from oil-only and dual-fuel resources (running on oil) given actual fuel inventory is calculated for each day. We calculate the minimum and average quantity of daily energy available over the course of the entire winter. These metrics provide information on the ability of oil-fired resources to provide energy and support reliable system operations across the winter. **Figure 27** to **Figure 29** show the daily level of these metrics for the Frequent, Extended and Infrequent Cases, respectively.

[56] How these products align with the region's reliability standards is also discussed in further detail in: Mark Karl and Peter Brandien, Letter to NEPOOL Markets Committee, December 4, 2019. https://www.iso-ne.com/static-assets/documents/2019/12/a6_c_i_memo_re_how_market_improvements_address_fuel_security.pdf

- ***Maximum 3-day drop in energy inventory.*** The largest drop in energy inventory during a 3-day period over the course of the winter. This metric provides information on how aggressively fuel inventories are being drawn down in response to stressed market conditions. In the past, rapid draw down of energy inventories has caused reliability concerns for the region.

Figure 27. Maximum Daily Potential Generation from Oil-fired Resources
CMR vs ESI, Winter Central Frequent Case (MWh)

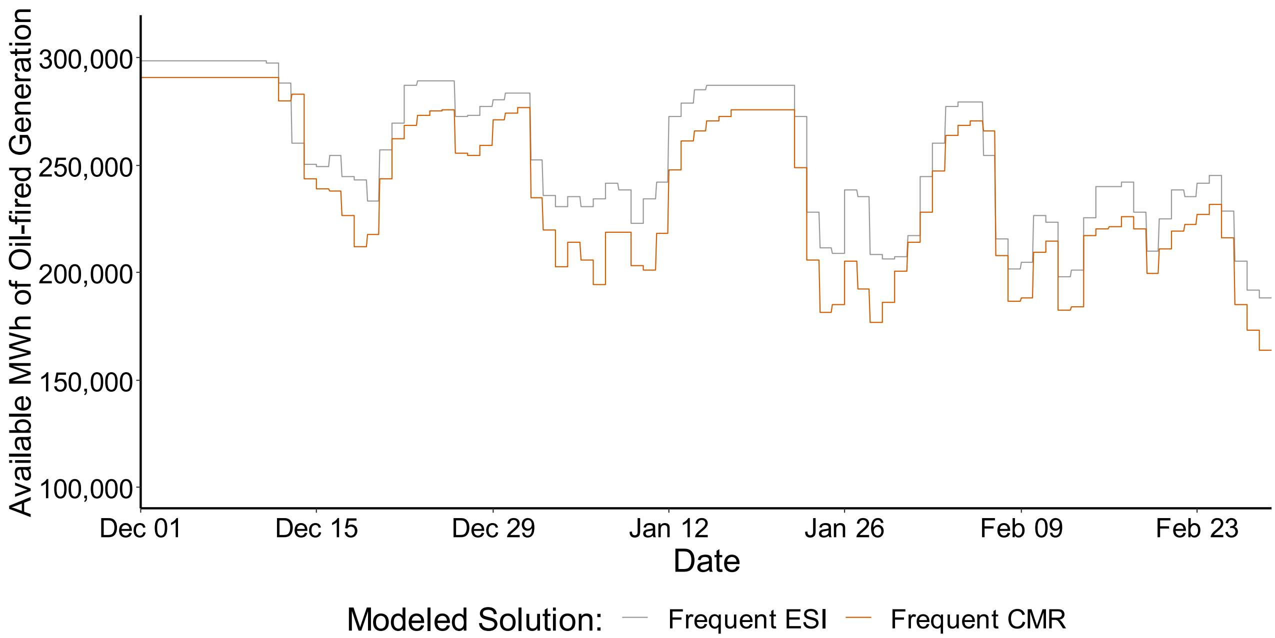


Figure 28. Maximum Daily Potential Generation from Oil-fired Resources
CMR vs ESI, Winter Central Extended Case (MWh)

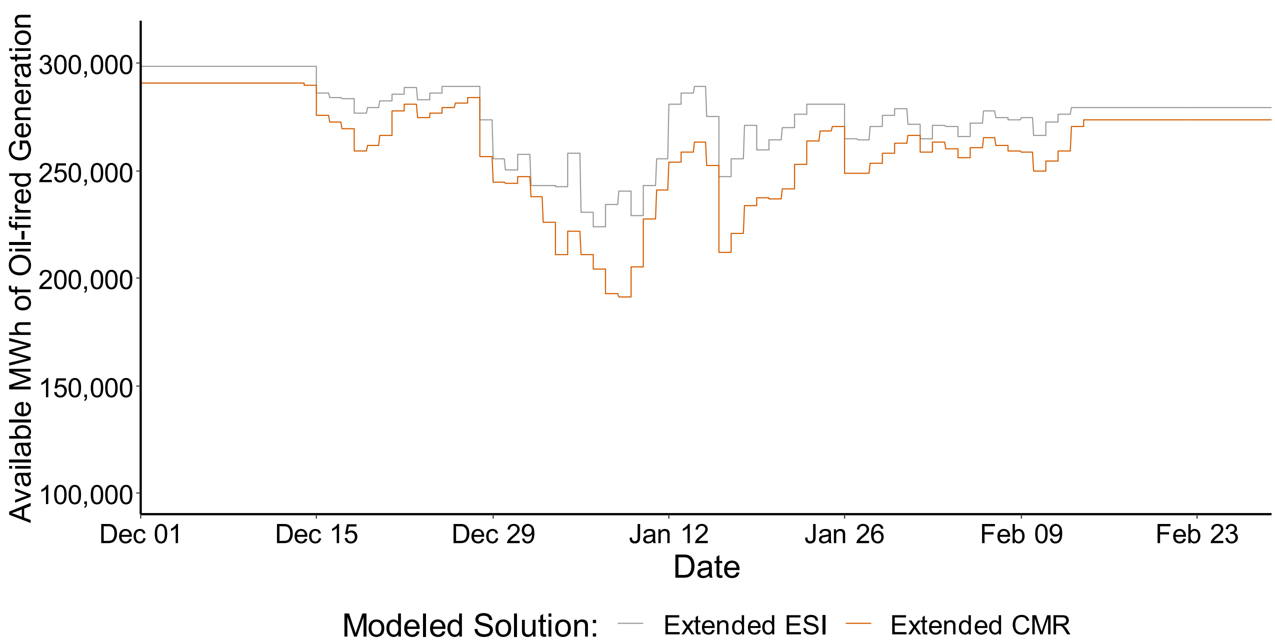


Figure 29. Maximum Daily Potential Generation from Oil-fired Resources
CMR vs ESI, Winter Central Infrequent Case (MWh)

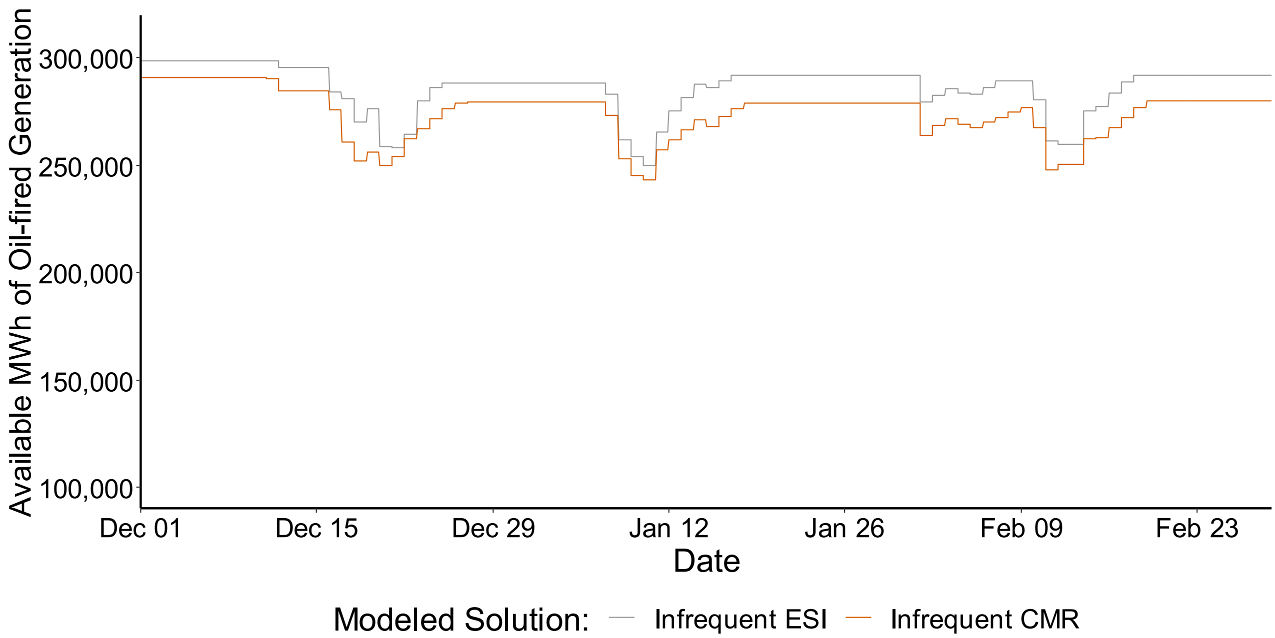


Table 29 provides the *change* in operational metrics with ESI compared to CMR Cases.[57] In general, these operational metrics indicate that there is less stress on physical energy systems and increased availability of energy inventory under ESI as compared to CMR. These results are consistent with improvements in reliability and improved energy security under ESI as compared to current market rules. For example, under ESI, natural gas consumption during stressed periods (with high natural gas prices) is reduced by 2.9 million MMBtu and 0.9 million MMBtu in the Frequent and Extended Cases, respectively. Similarly, the minimum and average quantity of oil inventory increases with ESI as compared to CMR across all Cases, with the increase in the average daily energy associated with inventoried oil ranging from 11.7 to 15.2 GWh. For the particular deterministic scenarios analyzed in the Central Case, there are no operating reserve shortages in either the CMR or ESI cases. However, as discussed above, our analysis is not designed to provide a thorough or complete analysis of system reliability and may make assumptions that lead it to overstate system reliability. It is notable that Scenarios considering supply contingencies, addressed in **Section IV.C.1.b**, find some operating resource shortages during certain contingencies. Thus, we caution against drawing inferences about the current or present reliability of the system from our results.

In addition, operational metrics tend to show that ESI provides a greater reliability benefit under stressed market conditions (Frequent and Extended Cases) as compared to unstressed market conditions (Infrequent Case). For example, the increase in daily oil-fired generation available due to ESI is greater in the Frequent

57 The levels for these operational metrics in the ESI and CMR cases are provided in the appendix.

and Extended Cases than in the Infrequent Case, particularly when comparing the minimum quantities of energy available over the winter. The same pattern is observed for the 3-day decline in oil inventories.

Table 29. Change in Operational Metrics, ESI v. CMR, Winter Central Case

Case	Operating Reserve Shortages (Hours)	Natural Gas Used in Generation When NG Economically Binding (MMBtu)	Daily Available Oil Generation Minimum (MWh)	Daily Available Oil Generation Average (MWh)	Daily Available Oil Generation Largest Three Day Decline
Frequent Case	0	(2,897,177)	24,512	15,204	(16,413)
Extended Case	0	(943,020)	32,663	14,022	(7,527)
Infrequent Case	0	0	6,753	11,656	(77)

B. Non-Winter Cases

To assess the impacts of ESI in non-winter months, we evaluate two non-winter Cases, a Moderate Case, reflecting moderate or typical market conditions, and a Severe Case, reflecting severe conditions with higher energy loads. Below, we summarize the estimated impacts on prices and compensation to energy supply, energy and option supply awards, customer payments and resource net revenues.

ESI would be expected to lead to an increase in payments by load during non-winter months. Estimated increases in payments are $89 million (3.6%) and $125 million (4.6%) in the Moderate and Severe Cases, respectively, over the nine-month non-winter period.

In our quantitative analysis of non-winter month impacts, we assume that market participant decisions related to real-time resource operations are the same in both the CMR and ESI cases. Thus, while we expect that ESI's incentives may have some effect on the decisions market participants make that affect their ability to reliably deliver energy supplies in real-time, such effects would be difficult to quantify, particularly for the market conditions assumed in our Central Case.

In addition, because the fuel supply during non-winter months does not face the constraints experienced in winter months, comparable shifts in fuel consumption between CMR and ESI cases do not occur in the non-winter month analyses. Given these factors, our quantitative analysis of real-time market outcomes produces the same outcomes in the CMR and ESI cases.[58] As a result, impacts that are based on changes in real-time outcomes (e.g., production costs and operational benefits) are not assessed because our analysis would not quantify any change that may occur.

[58] This outcome reflects a number of factors, including the fact that our model does not include unit commitment and many inter-temporal and operational constraints to unit operations. As a result, any changes associated with day-ahead clearing due to ESI do not affect real-time dispatch in our model, although such differences would be expected to arise in actual market operations.

While we do not quantify these effects, we expect that ESI would create reliability benefits and reductions in production costs during non-winter months, as well as during winter months.[59] Production costs would be expected to fall through the more orderly procurement of reserves in the day-ahead market. Reliability benefits would be expected from increasing the supply of energy in real-time to mitigate unanticipated contingencies or deviations between forecast and realized load. Such reliability benefits are most likely to occur under circumstances when large, sustained system contingencies occur, leaving the system vulnerable and straining the system's ability to recover 10- and 30-minute reserves consistent with NERC/NPCC standards. Further, changes in the composition of electric and natural gas infrastructure in the New England (and surrounding) region, including changes in resource mix in response to state incentives for renewable resources, could create market conditions in which energy security concerns become more pressing in non-winter months than at present. Under these circumstances, we would expect the reliability benefits that ESI would provide during non-winter months to increase beyond its ability to address unanticipated contingencies.

1. *Compensation to Energy Supply*

Table 30 provides the change in payments to energy for the three Central Cases. Changes reflect both the impact on LMPs and the additional FER payments. Across the two cases, DA LMPs are reduced by $0.18 per MWh in the Moderate Case and $0.23 per MWh in the Severe Case. These LMP changes are driven by the changes in energy that clears the day-ahead market, which occur because under ESI, the day-ahead market includes the FER. But, suppliers of physical DA energy receive FER payments, in addition to the LMP, with average FER payments of $0.76 per MWh in the Moderate Case and $1.12 per MWh in the Severe Case. Accounting for the net effect of these two components, total payments to DA energy increase in the two cases by $0.58 per MWh (Moderate Case) and $0.89 per MWh (Severe Case).

Table 30. Average DA Payments to Generators, Non-Winter Central Case

CMR vs ESI ($ per MWh)

	CMR	ESI				Change	
Case	Day-Ahead LMP [A]	Day-Ahead LMP [B]	FER [C]	Day-Ahead LMP + FER [D]=[B]+[C]	Real-Time LMP [E]	Day-Ahead LMP [B]-[A]	Day-Ahead LMP + FER [D]-[A]
Moderate Case	$27.90	$27.72	$0.76	$28.48	$28.35	($0.18)	$0.58
Severe Case	$29.81	$29.58	$1.12	$30.71	$30.65	($0.23)	$0.89

2. *Prices for ESI Ancillary Services*

The ESI proposal introduces new DA energy option products to the New England energy markets. **Table 31** reports average award prices for these products for the non-winter Cases. These prices are weighted averages, reflecting the quantity of each product procured in each hour.

[59] Both production costs and the operational metrics we measure to capture reliability benefits are based on real-time market outcomes. Because our analysis is not designed to capture changes in real-time dispatch between the CMR and ESI cases in non-winter months (as described above), our quantitative analysis would also not capture changes in production costs or these operational metrics.

Average ESI product prices are relatively consistent between Cases for GCR10, GCR30 and RER, ranging from $6.35 to $7.81 per MWh. For these products, the quantities are assumed to be the same in all hours, although in fact these quantities may differ from hour to hour.

Weighted average prices for EIR are higher than for the other ESI products, at $12.72 per MWh in the Moderate Case and $31.31 per MWh in the Severe Case. This occurs because the weights – EIR quantity – vary by hour and EIR prices tend to be higher in hours when EIR quantities are higher. Thus, even though prices in each hour for ESI products tend to be relatively similar, the weighted average EIR price is greater than for the other ESI products.

Table 31. Average DA Energy Option Clearing Prices, Non-Winter Central Case
($ per MWh)

Case	EIR/FER	GCR10	GCR30	RER
Moderate Case	$12.72	$6.36	$6.35	$6.35
Severe Case	$31.31	$7.81	$7.80	$7.80

3. Supply of Energy and DA Energy Options

Consistent with the winter Central Cases, introduction of the FER requirements causes the market to clear additional DA energy when there would otherwise be a gap between cleared energy supply and the load forecast. **Table 32** quantifies these adjustments, showing the changes in DA energy by resource type between CMR and ESI. Under CMR, the total energy clearing in the day-ahead market ranges between 88.0 and 90.2 TWh across Cases (column [A]). By contrast, under ESI, total cleared DA energy ranges between 89.6 and 91.5 TWh (column [B]). Thus, DA energy supply increases by 1.4 and 1.6 TWh, an increase of 1.5% and 1.8%, respectively, compared to current market rules (column [D]). These increases in DA energy happen as a consequence of the co-optimization of DA energy and EIR. While DA energy increases, there remains a gap between cleared DA energy and the forecast load in some hours. However, this gap is small, only 7.0 and 10.8 GWh, less than 0.1% of total load in both Cases.

Table 32. Changes in Cleared DA Energy, Non-Winter Central Case
CMR vs ESI (MWh)

	CMR	ESI		Difference	Real-Time Comparison	
Case	Day-Ahead Energy [A]	Day-Ahead Energy [B]	Cleared EIR [C]	Day-Ahead Energy [D] = [B] - [A]	Real-Time Demand	Energy + EIR [E] = [B] + [C]
Moderate Case	87,970,357	89,587,167	6,983	1,616,810	88,287,439	89,594,149
Severe Case	90,175,883	91,534,279	10,848	1,358,396	90,053,188	91,545,127

While overall DA energy supplies, including DA energy and DA energy options, increase in aggregate in both non-winter Cases, these impacts vary across resource types. **Table 33** and **Table 34** shows the impact of ESI on the products supplied in the day-ahead markets across resource types. While there are differences, the direction and magnitude of these impacts is very similar between the two non-winter Cases.

Compared to current market rules, ESI leads to a shift in the supply of DA energy across resource types. Nearly all resources increase the supply of DA energy, with the largest increases for combined cycle units (dual-fuel and gas-only), and smaller amounts for other resource types. DA energy options are supplied by a mix of resources, including (in order of quantity supplied) pumped storage, combustion turbines (all fuel types), hydro power and combined cycle units (dual fuel and gas-only). These supply patterns are similar to the patterns observed in the winter month Cases.

Table 33. Energy and DA Energy Options by Resource Type, Non-Winter Central Moderate Case
CMR vs ESI (MWh)

Resource Type	Summer SCC Capacity (MW)	DA CMR Energy (MWh)	DA ESI Energy (MWh)	DA Energy Options (MWh)	Change in DA Energy (MWh)
Active Demand Response	267	11	32	0	21
Battery Storage	458	125,906	125,906	0	0
Biomass/Refuse	830	4,249,546	4,261,671	0	12,125
Coal	531	167,617	177,373	23,906	9,755
Dual Fuel - CC	5,884	16,409,650	17,270,052	1,109,309	860,402
Dual Fuel - GT	1,237	777,989	776,349	4,203,326	(1,640)
Fuel Cell	21	4,929	5,537	0	608
Gas - CC	7,411	21,220,038	21,872,957	1,446,084	652,920
Gas - GT	364	10,993	7,395	1,270,802	(3,598)
Hydro	1,987	4,464,248	4,464,248	3,103,966	0
Imports	2,850	14,979,450	15,062,719	0	83,269
Nuclear	3,344	19,520,806	19,520,806	0	0
Offshore Wind	800	2,398,673	2,398,673	0	0
Oil Only - Steam	3,698	114	2,527	2,527	2,413
Oil Only - CT	2,114	0	0	5,063,873	0
Pumped Storage	1,778	1,882,553	1,882,553	7,542,569	0
Solar	1,671	1,968,609	1,968,609	0	0
Wind	1,401	2,472,822	2,472,822	0	0

Table 34. Energy and DA Energy Options by Resource Type, Non-Winter Central Severe Case
CMR vs ESI (MWh)

Resource Type	Summer SCC Capacity (MW)	DA CMR Energy (MWh)	DA ESI Energy (MWh)	DA Energy Options (MWh)	Change in DA Energy (MWh)
Active Demand Response	267	51	168	0	117
Battery Storage	458	125,906	125,906	0	0
Biomass/Refuse	830	4,295,501	4,296,836	0	1,336
Coal	531	252,245	272,980	38,705	20,735
Dual Fuel - CC	5,884	17,699,486	18,103,706	1,166,872	404,220
Dual Fuel - GT	1,237	792,172	797,347	4,154,426	5,175
Fuel Cell	21	6,460	7,478	0	1,018
Gas - CC	7,411	22,111,781	22,998,479	1,404,690	886,699
Gas - GT	364	25,141	28,663	1,256,090	3,522
Hydro	1,987	4,085,436	4,085,436	3,302,992	0
Imports	2,850	15,341,837	15,360,004	0	18,168
Nuclear	3,344	19,528,105	19,528,105	0	0
Offshore Wind	800	2,398,596	2,398,596	0	0
Oil Only - Steam	3,698	1,418	17,619	17,619	16,202
Oil Only - CT	2,114	0	37	2,970,196	37
Pumped Storage	1,778	1,882,553	1,882,553	9,457,666	0
Solar	1,671	1,863,549	1,863,549	0	0
Wind	1,401	2,448,824	2,448,824	0	0

4. *Impact of Customer Payments*

Total change in customer payments due to the ESI proposal will reflect a combination of factors: total LMP payments through day-ahead and real-time markets; compensation for meeting the FER; and new payments made in the day-ahead market for DA energy options. **Table 35** summarizes the net impact of these three components on total customer payments.

Total payments increase by $89 million in the Moderate Case, and $125 million in the Severe Case. Total payments for energy – LMPs and FER payments – increase in both cases, by $50 million and $78 million in the Moderate and Severe Cases, respectively (equal to the sum of the difference in energy and FER payments under ESI). Similarly, net payments for ESI products are $38 million and $47 million, respectively. In total, these changes represent a 3.6% and 4.6% increase in payments for the Moderate and Severe Cases, respectively.

Table 35. Non-Winter Total Payments, Non-Winter Central Case ($ Million)

		Moderate Case				Severe Case			
Product / Payment		**CMR**	**ESI**	**Difference**		**CMR**	**ESI**	**Difference**	
Energy and RT Operating Reserves	[A]	$2,473	$2,455	-$18	-0.7%	$2,697	$2,672	-$25	-0.9%
DA Energy Option									
DA Option Payment			$151				$186		
EIR			$0				$0		
RER			$50				$62		
GCR10			$67				$83		
GCR30			$34				$41		
RT Option Settlement			-$113				-$139		
Net DA Ancillary	[B]		$38				$47		
FER Payments	[C]		$68				$103		
Total Payments	[A+B+C]	$2,473	$2,562	$89	3.6%	$2,697	$2,822	$125	4.6%

In the context of all payments made by consumers for wholesale electric power services, these changes in payments are modest.[60] **Table 36** shows the total annual change in customer payments due to ESI for each of the possible combinations of winter and non-winter Central Cases evaluated. The annual changes in payments range from $20 million to $257 million, which, when compared to total payments of $12.24 billion in 2018, represents a 0.2% to 2.1% change in total payments.

Table 36. ESI Payment Impacts Relative to Total Customer Payments in ISO-NE Markets

Non-Winter Case		**Severe**			**Moderate**	
Winter Case	**Frequent**	**Extended**	**Infrequent**	**Frequent**	**Extended**	**Infrequent**
Incremental Payments from ESI	$257	$56	$160	$221	$20	$123
Percent of Total	2.1%	0.5%	1.3%	1.8%	0.2%	1.0%
Total Payments (2018)	$12,240	$12,240	$12,240	$12,240	$12,240	$12,240

5. *Resource Net Revenue*

As with the winter analysis, the impact of ESI on the net revenues earned by resources in non-winter months would depend on a combination of factors. In aggregate, changes in payments by load would lead to corresponding changes in revenues to generators. Thus, when payments to load are expected to increase as occurs in both non-winter Cases, this would be expected to lead to a corresponding increase in revenues to resource owners.

Table 37 and **Table 38** provide the average net revenues by resource type for the Moderate and Severe Cases, respectively. With a few exceptions, net revenues increase in both Cases. However, the magnitude of these changes varies across resources. These differences depend on a variety of factors, including resource-specific operational characteristics, such as plant operating efficiency and the ability to provide ESI ancillary services.

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60 Relative to all payments made by consumers for retail service, these payments would be smaller than the figures represented in **Table 35**.

Table 37. Average Net Revenues by Resource Type, Non-Winter Central Moderate Case ($ per MW – 9-Non-Winter Months)

	Net Revenue ($/MW Capacity)		
	CMR	ESI	Change
Resource Type:	[A]	[B]	[C] = [B] - [A]
Dual Fuel - CC	$7,914	$9,899	$1,985
Dual Fuel - GT	$6,782	$12,721	$5,940
Gas Only - CC	$8,265	$10,323	$2,058
Gas Only - GT	$562	$6,823	$6,261
Oil Only - Steam	$23	$47	$24
Oil Only - CT	$353	$2,502	$2,149
Coal	$5,353	$6,296	$943
Biomass/Refuse	$134,779	$137,212	$2,433
Fuel Cell	$3,463	$3,616	$153
Hydro	$67,892	$71,579	$3,686
Nuclear	$158,399	$161,162	$2,764
Solar	$31,080	$31,482	$402
Wind	$49,772	$50,583	$811
Offshore Wind	$81,640	$82,839	$1,198

Table 38. Average Net Revenues by Resource Type, Non-Winter Central Severe Case ($ per MW – 9-Non-Winter Months)

	Net Revenue ($/MW Capacity)		
	CMR	ESI	Change
Resource Type:	[A]	[B]	[C] = [B] - [A]
Dual Fuel - CC	$9,872	$13,158	$3,286
Dual Fuel - GT	$8,380	$15,971	$7,591
Gas Only - CC	$10,264	$13,555	$3,291
Gas Only - GT	$1,382	$9,027	$7,645
Oil Only - Steam	$192	$241	$50
Oil Only - CT	$606	($83)	($689)
Coal	$9,411	$9,394	($18)
Biomass/Refuse	$145,754	$149,222	$3,468
Fuel Cell	$6,964	$7,457	$493
Hydro	$69,230	$74,225	$4,995
Nuclear	$170,861	$174,801	$3,940
Solar	$32,442	$33,300	$858
Wind	$53,491	$54,569	$1,078
Offshore Wind	$88,152	$89,830	$1,678

C. Scenario Analysis

As described earlier, the Central Cases make specific assumptions about the future resource mixes and fuel levels, and consider various load and weather conditions based on historic data. These cases are intended to represent potential future scenarios for 2025/26 in which system resources and market conditions would remain (relatively) unchanged from today. While these Central Cases are reasonably plausible, there is substantial uncertainty about how market and system conditions will change between now and the time when ESI would come into effect.

We have therefore modeled a number of additional Scenarios. These Scenarios generally start with the winter Central Case analysis and change one (or several) key assumptions, but otherwise keep all assumptions the same. For each Scenario, we evaluate the same Frequent, Extended and Infrequent Cases that are evaluated in the Central Case, thus assessing how the Scenario results may be impacted by load and weather conditions.

Several different types of scenarios are evaluated. ***First***, we consider ESI's impacts under ***different assumptions about future market conditions***, as described in **Table 39**. These Scenarios will help illustrate how ESI would be expected to affect market outcomes under a range of market and system conditions, including those with more and less frequent stressed system conditions, and those in which energy costs are higher than is assumed in the Central Cases. Particular future assumptions tested include changes to the region's mix of electric power resources, the infrastructure that delivers fuel to the region, and load growth.

Table 39. Winter Scenarios Evaluating Changes in Market or System Conditions

No Fuel-Related Market Response	
Risk Premium x1.25	"Central Case" with DA energy option offers calculating using risk premia set at 125% of Central Case levels.
Supply Shocks	Unexpected real-time outages, experienced during coldest portion of historic winter.
Shock HQ 1 Day	Supply shock (outage) fo 1,364 MW is modeled in real-time market, but not modeled in day-ahead market. - Frequent Stressed Conditions: January 3, 2014 (average temperature 4.77 F); - Extended Stressed Conditions: January 1, 2018 (average temperature 2.72 F); - Infrequent Stressed Conditions: December 16, 2016 (average temperature 11.64 F).
Shock HQ 5 Days	Supply shock of 1,364 MW is modeled in Day-1 real-time market, but not expected in Day 1 day-ahead market. Resource is expected out day-ahead in remaining days (Days 2-5). - Frequent Stressed Conditions: January 21-25, 2014 (average temperature 12.83 F); - Extended Stressed Conditions: December 28, 2017 - January 1 2018 (average temperature 5.68 F); - Infrequent Stressed Conditions: January 6-10, 2016 (average temperature 19.07 F).
High LNG Supply	Assume additional LNG availability of 0.4 Bcf/day to both ESI and CMR cases (all winter severities). Under ESI, assume an incremental 0.4 Bcf/day available for LNG forward contracts, for a total of 0.52 Bcf/day available for forward contracts.
Low LNG Supply	Assume reduced LNG availability of 0.12 Bcf/day in both ESI and CMR cases for all winter severities (corresponding to LNG forward contract).
High Load	Load is increased by 5%, with no other modeling changes.
Oil Retirements	For oil retirement scenarios: 1,500 MW of retirements based on FCA13 delist bids plus an additional ~1,000 MW of oil resources retired.
With Renewable Replacement	3,824 MW nameplate (1,400 MW derated) of new offshore wind, and 1,200 MW of new hydro imports.
Nuclear Retirements	For nuclear retirement scenarios: 1,500 MW of retirements based on FCA13 delist bids plus an additional ~3,500 MW of nuclear resources retired.
With Renewable Replacement	8,824 MW nameplate (3,000 MW derated) of new offshore wind, 5,333 MW nameplate (800 MW derated) of new onshore wind, and 1,200 MW of new hydro imports.
With Fuel-Related Market Response	
Oil Retirements	For oil retirement scenarios: 1,500 MW of retirements based on FCA13 delist bids plus an additional ~1,000 MW of oil resources retired.
With Gas Replacement	2,500 MW of new natural gas CC resources, none with dual-fuel capability, and 0.3 Bcf/day of additional NG supply
With Gas / Dual Fuel Replacement	2,500 MW of new natural gas CC resources, 50% with dual-fuel capability, and 0.3 Bcf/day of additional NG supply
Nuclear Retirements	For nuclear retirement scenarios: 1,500 MW of retirements based on FCA13 delist bids plus an additional ~3,500 MW of nuclear resources retired.
With Gas Replacement	5,000 MW of new natural gas CC resources, none with dual-fuel capability and 0.7 Bcf/day of additional NG supply
With Gas / Dual Fuel Replacement	5,000 MW of new natural gas CC resources, 50% with dual-fuel capability, and 0.7 Bcf/day of additional NG supply

Second, we consider the impacts of ***different ESI designs***. **Table 40** describes these Alternative Proposals, which include designs that change the quantity of procured ESI products (in some cases, reducing them to 0 MWh), and designs with an energy option strike price that differs from the ISO-NE proposal. These Alternate Proposals are provided in response to feedback and requests during the stakeholder process. Assessing the market and reliability impacts under these alternate proposals will provide information about market and operational outcomes for these alternate designs, which have been discussed with stakeholders.

Table 40. Winter Scenarios Evaluating Alternate ESI Proposals

No Fuel-Related Market Response	
RER Plus	"Central Case" with RER requirement set to 150% of Central Case level (1,800 MW).
Strike Plus $10	"Central Case" with DA energy option strike price = Central Case strike price + $10 in all hours; adjustment affects all calculations, incuding risk premia.
With Fuel-Related Market Response	
No EIR/RER	"Central Case" with no RER nor EIR requirement. Under ESI, there is no incremental fuel relative to amounts assumed under CMR.
No RER	"Central Case" with no RER requirement. Under ESI, incremental fuel (i.e., relative to CMR) is assumed to be one-half of the incremental fuel amounts assumed in the Central Case.

Third, we consider one Scenario in which the ***ESI design is unchanged from the ISO-NE proposal, but causes no change in the fuel inventory and refueling decisions of market participants***. We do not evaluate this Scenario because we expect there to be no change in fuel inventories if ESI were adopted (recall, **Section IV.1** found that ESI generally increases the incentive to hold fuel relative to current market rules). Rather, this Scenario provides information on the impact of the ESI proposal, apart from the impact of the incremental fuel inventory due to the new incentives created by ESI.

Fourth, we consider two ***non-winter Scenarios***, both involving different ESI design elements. One Scenario assumes no RER product in non-winter months (analogous to the “No RER” winter Scenario), while the second Scenario assumes a strike price set $10 per MWh above the expected RT LMP (analogous to the “Strike Plus $10” winter Scenario).

Table 41. Non-Winter Scenarios

No Fuel-Related Market Response	
Strike Plus $10	"Central Case" with DA energy option strike price = Central Case strike price + $10 in all hours; adjustment affects all calculations, incuding risk premia.
With Fuel-Related Market Response	
No RER	"Central Case" with no RER requirement. Under ESI, incremental fuel (i.e., relative to CMR) is assumed to be one-half of the incremental fuel amounts assumed in the Central Case.

While our model captures many of the market adjustments that occur with new Scenario assumptions, it does not endogenously capture all effects. In particular, the model does not endogenously adjust aggregate fuel supplies or resource-level fuel inventory decisions for changes in market design or market conditions.[61] In general, however, we would expect market responses to depend on underlying assumptions about market tightness and market design. For example, if changes to energy supply or demand occurred that reduced the region’s energy security (where these changes could be caused by resource retirements, changes in load, or

[61] In principle, these adjustments can include market, regulatory and policy responses to market conditions. With regard to regulatory and policy responses, we take no position on the form of any such policy response, but acknowledge that such responses could occur.

other factors), we may also observe potential changes in fuel supply and demand, such as new sources of LNG supplies, new infrastructure (e.g., LDC peak shavers), and new dual fuel capability.

While we expect some degree of market response in many Scenarios, the magnitude of this expected response varies. Thus, for Scenarios in which we expect the market response to be comparatively smaller, we make no additional change from the Central Case (beyond the core change assumed in the Scenario), whereas in Scenarios in which we expect a larger market response, we modify certain assumptions from the Central Case related to fuel.

Table 39 and **Table 40** identify the Scenarios with fuel assumptions that are the same as the Central Case, and the Scenarios with fuel assumptions that differ from the Central Case, respectively. In Scenarios assuming substantial retirements of oil or nuclear resources with replacement by natural gas-fired resources, we assume a market response to these retirements, as the increased dependence on natural gas-fired resources would cause an increase in demand that stimulates greater natural gas supply available to the region. This market response could come in one of many different forms, such as additional natural gas supplies through an LNG terminal, development of new LDC peak-shaving facilities to relieve reliance on the remaining LNG terminals, or additional dual-fuel capability (which would also reduce the dependence on the region's gas infrastructure). In these Scenarios, we assume the incremental fuel supply is present in both the CMR and ESI Cases, as the retirements are also assumed in both cases.

Likewise, several Scenarios assume alternative designs that would be expected to reduce the incentives to retain fuel supplies relative to the ISO's ESI proposal. In some of these Scenarios, we reduce the quantity of incremental fuel in the ESI Case to reflect this impact. In these cases, we keep the assumptions in the CMR Case unchanged, as these Scenarios do not contemplate any changes in underlying market conditions common to both CMR and ESI Cases.

There are many Scenarios that assume no changes in fuel supplies or inventories relative to those assumed under ESI in the winter Central Cases. This does not imply that no such changes would occur, in actuality, but rather that one can reasonably assume that any such changes may be modest. Moreover, although we make best efforts to develop reasonable assumptions about fuel supply or inventory response in each Scenario, these assumptions are not forecasts or precisely estimated adjustments.

Thus, when comparing *between* Scenarios (and between the Central Cases and Scenarios), care should be taken to recognize that the results represent plausible market and operational impacts of the market rule changes, but are not intended to be definitive. Because counterfactual assumptions about fuel availability (market supplies and inventory) and potentially other factors are not carefully calibrated, quantitative comparisons between Scenarios may not provide a balanced "apples-to-apples" comparison. Nonetheless, these Scenarios do help to shed further light on the possible impacts of ESI across various market conditions and design changes, and also help to illustrate the model's sensitivities to key input assumptions.

The results of our Scenario analysis are reported in the body of this report and with additional detail in a supplemental appendix. In the body of this report, we provide the impacts (changes) on prices and payments, and the impacts (changes) on operational metrics indicative of potential reliability benefits.

- For the Scenarios evaluating the ***changes in market or system conditions***, **Table 42** to **Table 44** report the changes in prices (LMPs, ESI prices) and total payments for the Frequent, Extended and Infrequent Cases, respectively, while **Table 45** to **Table 47** provide the changes in operational metrics for the Frequent, Extended and Infrequent Cases, respectively. In each table, the Central Case results are presented for comparison purposes.

- For the Scenarios evaluating the changes in ***ESI market design*** and the Scenario assuming ***no incremental ESI fuel***, **Table 48** to **Table 50** report the changes in prices (LMPs, ESI prices) and total payments for the Frequent, Extended and Infrequent Cases, respectively, while **Table 51** to **Table 53** provide the changes in operational metrics for the Frequent, Extended and Infrequent Cases, respectively. In each table, the Central Case results are presented for comparison purposes.

The supplemental appendix provides these results plus the impacts on shortage hours of day-ahead and real-time ancillary services, as well as the levels for the prices and payments, operational metrics, and shortage hours for both the CMR and ESI Cases.

1. Scenarios Evaluating Changes in Market or System Conditions

a) Risk Premium

The Risk Premium plus 25% Scenario assumes a 25% increase in all risk premiums for DA energy option offers in the ESI run compared to the Central Case estimates. This Scenario provides information on the sensitivity of impacts to the cost of procuring the DA energy options. With the higher risk premiums, total payments increase by $42 million, $29 million and $13 million compared to Central Case payments for the Frequent, Extended and Infrequent Case, respectively. Most of this change in payments is due to the higher net cost of the DA energy options, which increase by $41 million, $25 million and $10 million, respectively, in the Frequent, Extended and Infrequent Cases. By contrast, the net cost for energy (LMPs plus FER payments) remains relatively unchanged.

While this Scenario provides information on the sensitivity of impacts to general (uniform) shifts in the magnitude of the DA energy option offers, it is not intended to represent the potential impacts of the exercise of seller-side market power on market outcomes. Such analysis is outside the scope of this report.

b) Supply Shocks

The supply shock Scenarios assume 1-day and 5-day supply contingencies, in which imports are reduced by 1,364 MW during stressed market conditions. In the first day of both Scenarios, the resource is assumed to be available in the day-ahead market but not in the next day's real-time market. In the scenario with the prolonged 5-day shock, the unavailable resource is also excluded from the day-ahead market in subsequent days. Other than these supply shocks, the Scenarios are otherwise the same as the Central Case.

In the Frequent Case, ESI has a smaller impact on total payments with supply shocks (as compared to the Central Case), suggesting that ESI reduces total payments during supply shocks. With ESI, total payments increase by $123 million for the 1-day shock and $92 million for the 5-day shock, both less than increase in total payments of $132 million in the Central Case with no shocks. Thus, total payments are $9 million and $40 million lower with ESI in place when a 1-day and 5-day shock occur, respectively. These results suggest that ESI can lower total payments during stressed market conditions. The reductions in payments occur because ESI's incentives for energy inventory would be expected to increase inventoried energy supply, which can lower LMPs during tight market conditions including the period where the contingency occurs.

In the Extended and Infrequent Cases, however, ESI does not have a large impacts on total payments during supply shocks. In the Extended Case, ESI reduces payments by $72 million with a 1-day shock and $66 million with a 5-day shock, both similar to the $69 million reduction in payments impacts in the Central Case with no supply shocks. These results suggest that under some system conditions, ESI may have a relatively small impact on total payments during a supply shock, potentially increasing or decreasing payments. Results in the Infrequent Case are similar – ESI increases payments $34 million with a 1-day shock and $36 million with a 5-day shock, similar to the $35 million increase in costs in the Central Case with no shocks.

Detailed analysis of market outcomes illustrates how market responses to a supply contingency may differ under ESI as compared to current market rules. **Figure 30** shows RT LMPs during the supply contingency, while **Figure 31** shows the aggregate fuel oil inventory. With the higher fuel inventory incented by ESI, the market is able to maintain a supply of energy able to meet real-time loads plus reserve requirements. However, absent this incremental fuel from ESI, the system is short of operating reserves in some hours, and high energy and reserve prices reflect each product's relatively scarcity.

Figure 30. Real-Time LMPs during 5-Day Supply Shock, 5-Day Shock Frequent Case
CMR versus ESI

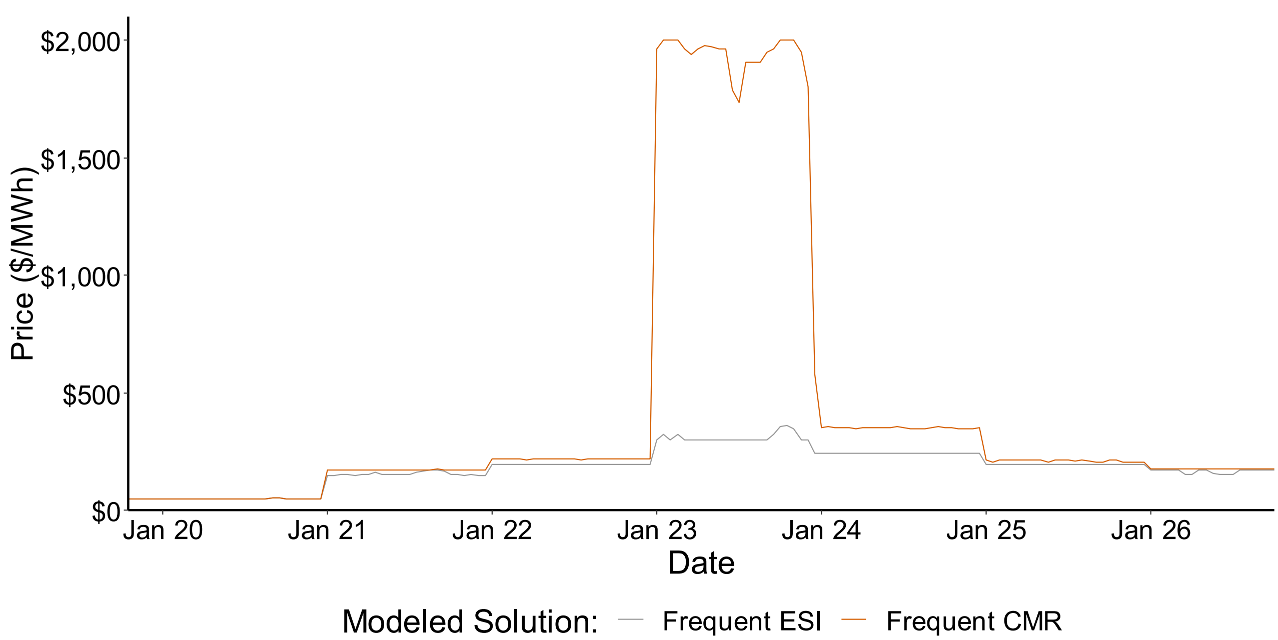
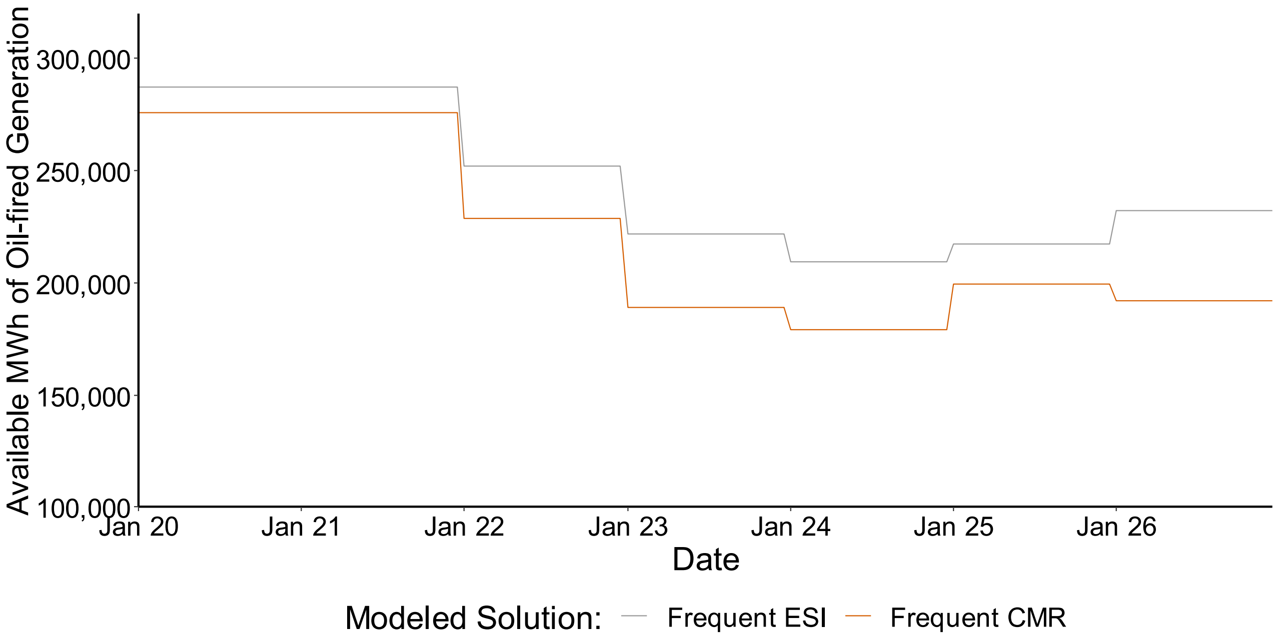


Figure 31. Aggregate Fuel Oil Inventory during 5-Day Supply Shock, 5-Day Shock Frequent Case
CMR versus ESI



Operational metrics generally show larger improvements consistent with reliability benefits compared to the Central Case. In the Frequent Case, ESI avoids three hours of operating reserve shortages that occur under current market rules during the 5-day Supply Shock. Metrics related to natural gas and oil supply generally show larger improvements than the Central Case, suggesting that ESI's reliability impacts may be more significant during periods of system stress due to unexpected contingencies, with improvements being the greatest in the Extended Case.

c) LNG Supply

The LNG Supply Scenarios consider both a higher quantity of daily LNG supply (increased by 0.4 Bcf) and a lower quantity of LNG supply (decreased by 0.12 Bcf) compared to the Central Case. The change in LNG supply is assumed in both the CMR and ESI Cases, and the amount of fuel oil incented by ESI is the same as the Central Case.

Compared to the Central Case, higher LNG supply would tend to reduce ESI's impact on total payments, while lower LNG supply would tend to increase ESI's impact on total payments. These effects are most pronounced during stressed market conditions. With the assumed higher quantity of LNG supply, ESI's impact on total payments is $50 million (Frequent Case) and $108 million (Extended Case) – these are $182 million and $39 million lower than in the Central Cases respectively. By contrast, with lower LNG supplies, total payments in the Frequent Case are $154 million higher with ESI (as compared to CMR) and in the Extended Case are $15 million lower with ESI (compared to CMR) – these values reflect $22 million and $54 million higher costs than in the Central Cases). In unstressed market conditions, the change in LNG supply leads to no meaningful change in payment impacts compared to the Central Case.

d) High Load

The High Load Scenario assumes higher load than is assumed in the Central Cases, with no adjustments to capacity or available energy inventory. With high loads, ESI is estimated to reduce total payments by $322 million and $256 million in the Frequent and Extended Cases, respectively. In both of these stressed conditions cases, ESI's impacts are substantially different than the Central Case, causing large reductions in total payments relative to current market rules. In the Infrequent Case, ESI is estimated to increase payments by $35 million, which is very similar to the Central Case.

The reductions in payments in the stressed conditions cases are driven by the reduction in DA LMPs ($23.92 per MWh and $14.33 per MWh in the Frequent and Extended Cases, respectively) that occur because of the incremental energy inventory incented by ESI. Prices for FER and DA energy options are also larger than in the Central Case. However, the LMP reductions are sufficiently large to offset payment for these ancillary services.

ESI produces operational benefits, particularly under the Frequent and Extended stressed conditions Cases. These impacts vary in magnitude from the Central Case, and are larger in many but not all cases.

e) Retirements

Multiple retirement Scenarios are evaluated. We consider retirement of a set of at-risk oil resources (approximately 1,000 MW) and both remaining nuclear plants (Millbrook and Seabrook, approximately 3,500 MW). For both sets of assumed retirements, we run three distinct Scenarios with retired resources replaced by three different types of new resources: (i) renewable resources, (ii) all gas-only combined cycle resources, or (iii) a mix of gas-only and dual fuel combined cycle resources. Thus, in total, we evaluate six retirement Scenarios (two sets of retirements and three sets of replacement resources for each retirement).

In these retirement Scenarios, we consider whether the retirements would likely prompt a market response in the fuels market, given the potential change in fuel demand from the electricity sector. When retirements are replaced by renewables, we do not assume any market response, as the renewables are not likely to increase fuel demand. In the other Scenarios, the replacement of oil or nuclear plants with resources relying on natural gas will tend to increase demand for natural gas. We assume a corresponding market response that increases the potential supply of natural gas to the electricity sector under both the CMR and ESI runs. We do not identify the source of this supply, which, in principle, could come from LNG supplies (e.g., through the Northeast Gateway buoy), expanded dual fuel capacity, additional LDC "peak shaving" infrastructure (i.e., satellite LNG tanks), and/or other sources. The quantity of incremental fuel we assume reflects an evaluation of the change in LMPs with different levels of incremental natural gas, under the premise that these price signals would drive demand for increased supplies. In the oil retirement cases, we assume an additional 0.3 Bcf of fuel is available each day, while in the nuclear cases we assume an additional 0.7 Bcf. While we adjust the assumptions about aggregate fuel supply, we do not adjust assumptions about the response of market participants to ESI incentives via the procurement of additional oil.

When renewables replace retired resources, the impact of ESI on total payments is ambiguous, increasing payments in some cases and decreasing it in others, compared to the Central Case. At the extremes, ESI's impact on total payments is $50 million higher than the Central Case in one case (Frequent, nuclear retirements replaced by renewables), and $103 million lower than the Central Case in another (Extended, nuclear retirements replaced by renewables). However, compared to the Central Case, renewable replacements generally lead to smaller LMPs reductions (due to ESI) and larger net costs of DA energy options. For example, in the Extended Case, the reduction in average energy costs (due to ESI) is $6.43 per MWh in the Central Case compared to $2.66 per MWh when nuclear resources are replaced by renewables. But, net payments for DA energy options fall from $32 million in the Central Case to $20 million and $21 million for the oil and nuclear retirements, respectively.

When gas-only or a mix of gas-only and dual fuel replace the retired resources, the impact of ESI on payments is very large in magnitude compared to impacts in the Central Case, though in some cases the costs increase whereas in others they decrease. For example, while impacts vary from an increase of $132 million to a decrease of $69 million in the Central Case, ESI impacts vary from an increase of $531 million to a decrease of $193 million with gas/dual fuel replacements for retired resources. This difference in the magnitude of these impacts reflects the sensitivity of the market outcomes as the region increases its reliance on natural gas resources.

While the magnitude of the impacts is greater across these retirement Scenarios, the direction of these impacts differs across stressed cases. In the Frequent Case, the retirement scenario magnifies the increase in cost compared to the Central Case, with ESI impacts rising as high as $531 million ($399 million greater than in the Central Case). However, in the Extended Case, the retirement scenarios magnifies the decrease in total payments caused by ESI compared to the Central Case, with payments decreasing by as much as $193 million ($124 million lower than in the Central Case).

In all Scenarios, the incremental inventoried energy incented by ESI reduces LMPs, but net payments for energy increase in some cases (for example, all Frequent Cases) and decease in other cases (for example, 3 of 4 Extended Cases). Net payments for DA energy options range from $33 million to $119 million across stressed Cases.

Table 42. Scenarios Evaluating Changes in Market or System Conditions - Prices & Payments, Winter Frequent Case

	Weighted Average Prices ($/MWh)			Customer Payment ($ Million)		
Scenario Name/Acronym	Change in DA LMP (ESI - CMR)	Average FER Price	Average Option Price (GCR, RER)	Change in Energy and Ancillary Services (+ FER in ESI) (ESI - CMR)	Energy Options (DA Cost Net of RT Settlement)	Change in Total Customer Payments
Frequent Case						
Central Case	($5.49)	$7.76	$27.00	$67	$66	$132
No Fuel-Related Market Response						
Risk Premium x1.25	($5.52)	$7.80	$32.33	$67	$107	$174
Shock HQ 1 Day	($5.62)	$7.78	$27.00	$57	$65	$123
Shock HQ 5 Days	($19.35)	$20.59	$33.19	($23)	$115	$92
High LNG Supply	($9.02)	$6.17	$24.64	($98)	$48	($50)
Low LNG Supply	($6.86)	$9.39	$29.10	$77	$77	$154
High Load	($23.92)	$11.99	$30.78	($412)	$90	($322)
Oil Retirements; Renewable Replacement	($4.76)	$5.62	$23.46	$42	$40	$82
Nuclear Retirements; Renewable Replacement	($5.21)	$6.61	$25.05	$96	$53	$149
With Fuel-Related Market Response						
Oil Retirements; Gas Replacement	($5.60)	$18.75	$33.69	$412	$119	$531
Oil Retirements; Gas / Dual Fuel Replacement	($7.17)	$8.75	$28.71	$41	$74	$115
Nuclear Retirements; Gas Replacement	($5.04)	$9.40	$29.51	$126	$78	$204
Nuclear Retirements; Gas / Dual Fuel Replacement	($3.99)	$9.47	$28.07	$166	$72	$238

Table 43. Scenarios Evaluating Changes in Market or System Conditions - Prices & Payments, Winter Extended Case

	Weighted Average Prices ($/MWh)			Customer Payment ($ Million)		
Scenario Name/Acronym	Change in DA LMP (ESI - CMR)	Average FER Price	Average Option Price (GCR, RER)	Change in Energy and Ancillary Services (+ FER in ESI) (ESI - CMR)	Energy Options (DA Cost Net of RT Settlement)	Change in Total Customer Payments
Extended Case						
Central Case	($6.43)	$3.55	$14.46	($100)	$32	($69)
No Fuel-Related Market Response						
Risk Premium x1.25	($6.47)	$3.71	$17.66	($97)	$57	($40)
Shock HQ 1 Day	($6.58)	$3.59	$14.44	($104)	$32	($72)
Shock HQ 5 Days	($7.14)	$4.17	$15.24	($104)	$38	($66)
High LNG Supply	($6.01)	$2.26	$13.03	($129)	$21	($108)
Low LNG Supply	($7.28)	$5.70	$16.28	($60)	$45	($15)
High Load	($14.33)	$5.69	$16.44	($303)	$46	($256)
Oil Retirements; Renewable Replacement	($4.10)	$2.17	$12.98	($55)	$20	($35)
Nuclear Retirements; Renewable Replacement	($2.66)	$2.00	$13.10	$13	$21	$34
With Fuel-Related Market Response						
Oil Retirements; Gas Replacement	($9.05)	$4.52	$15.82	($160)	$38	($122)
Oil Retirements; Gas / Dual Fuel Replacement	($10.30)	$3.69	$15.02	($225)	$33	($193)
Nuclear Retirements; Gas Replacement	($8.33)	$14.92	$20.36	$192	$81	$274
Nuclear Retirements; Gas / Dual Fuel Replacement	($9.07)	$4.26	$15.03	($170)	$35	($135)

Table 44. Scenarios Evaluating Changes in Market or System Conditions - Prices & Payments, Winter Infrequent Case

	Weighted Average Prices ($/MWh)			Customer Payment ($ Million)		
Scenario Name/Acronym	Change in DA LMP (ESI - CMR)	Average FER Price	Average Option Price (GCR, RER)	Change in Energy and Ancillary Services (+ FER in ESI) (ESI - CMR)	Energy Options (DA Cost Net of RT Settlement)	Change in Total Customer Payments
Infrequent Case						
Central Case	($1.20)	$1.94	$5.75	$20	$15	$35
No Fuel-Related Market Response						
Risk Premium x1.25	($1.30)	$2.13	$7.13	$22	$25	$48
Shock HQ 1 Day	($1.24)	$1.96	$5.76	$19	$15	$34
Shock HQ 5 Days	($1.28)	$2.06	$5.88	$21	$16	$36
High LNG Supply	($0.76)	$1.58	$5.71	$21	$14	$36
Low LNG Supply	($1.50)	$2.07	$5.79	$15	$15	$30
High Load	($1.45)	$2.16	$5.82	$20	$15	$35
Oil Retirements; Renewable Replacement	($1.28)	$1.45	$5.66	$18	$14	$31
Nuclear Retirements; Renewable Replacement	($1.72)	$1.70	$5.71	$27	$14	$42
With Fuel-Related Market Response						
Oil Retirements; Gas Replacement	($1.01)	$1.77	$5.71	$20	$14	$35
Oil Retirements; Gas / Dual Fuel Replacement	($1.14)	$1.76	$5.69	$16	$14	$30
Nuclear Retirements; Gas Replacement	($1.16)	$1.94	$5.74	$21	$15	$35
Nuclear Retirements; Gas / Dual Fuel Replacement	($1.71)	$1.97	$5.70	$5	$14	$19

Table 45. Scenarios Evaluating Changes in Market or System Conditions - Operational Metrics, Winter Frequent Case

Scenario Name/Acronym	Operating Reserve Shortages (Hours)	NG Used in Generation when NG Supply is Tight (MMBtu)	Daily Available Oil Generation Minimum (MWh)	Daily Available Oil Generation Average (MWh)	Daily Available Oil Generation Largest Three Day Decline (MWh)
Frequent Case					
Central Case	0	(2,897,177)	24,512	15,204	(16,413)
No Fuel-Related Market Response					
Risk Premium x1.25	0	(2,900,847)	24,421	15,204	(16,536)
Shock HQ 1 Day	0	(2,858,688)	24,512	15,661	(14,689)
Shock HQ 5 Days	(3)	(2,977,660)	27,997	15,904	(14,745)
High LNG Supply	0	(5,097,543)	14,821	17,475	(33,510)
Low LNG Supply	0	(1,906,929)	29,003	16,925	(8,740)
High Load	0	(3,618,832)	13,663	17,991	(23,414)
Oil Retirements; Renewable Replacement	0	(1,117,137)	20,525	14,228	(1,134)
Nuclear Retirements; Renewable Replacement	0	(878,402)	20,550	15,364	(5,703)
With Fuel-Related Market Response					
Oil Retirements; Gas Replacement	0	(6,395,750)	26,098	10,679	731
Oil Retirements; Gas / Dual Fuel Replacement	0	(6,272,248)	16,245	13,935	(8,465)
Nuclear Retirements; Gas Replacement	0	(12,322,023)	10,131	9,608	(9,084)
Nuclear Retirements; Gas / Dual Fuel Replacement	0	(12,852,218)	32,986	13,687	(14,422)

Table 46. Scenarios Evaluating Changes in Market or System Conditions - Operational Metrics, Winter Extended Case

Scenario Name/Acronym	Operating Reserve Shortages (Hours)	NG Used in Generation when NG Supply is Tight (MMBtu)	Daily Available Oil Generation Minimum (MWh)	Daily Available Oil Generation Average (MWh)	Daily Available Oil Generation Largest Three Day Decline (MWh)
Extended Case					
Central Case	0	(943,020)	32,663	14,022	(7,527)
No Fuel-Related Market Response					
Risk Premium x1.25	0	(943,020)	32,663	14,022	(7,527)
Shock HQ 1 Day	0	(943,020)	34,807	14,918	(1,041)
Shock HQ 5 Days	0	(1,009,333)	28,426	15,398	(7,076)
High LNG Supply	0	(3,440,918)	40,214	15,327	(5,925)
Low LNG Supply	0	(79,946)	26,394	15,528	(11,646)
High Load	0	(851,854)	25,828	15,910	(6,214)
Oil Retirements; Renewable Replacement	0	(614,918)	10,799	12,116	(3,790)
Nuclear Retirements; Renewable Replacement	0	(332,387)	28,510	12,340	(14,390)
With Fuel-Related Market Response					
Oil Retirements; Gas Replacement	0	(3,484,459)	10,230	13,081	1,860
Oil Retirements; Gas / Dual Fuel Replacement	0	(3,497,787)	12,036	15,045	(4,948)
Nuclear Retirements; Gas Replacement	0	(7,662,525)	20,129	12,803	(8,296)
Nuclear Retirements; Gas / Dual Fuel Replacement	0	(7,277,589)	12,911	16,611	(14,536)

Table 47. Scenarios Evaluating Changes in Market or System Conditions - Operational Metrics, Winter Infrequent Case

Scenario Name/Acronym	Operating Reserve Shortages (Hours)	NG Used in Generation when NG Supply is Tight (MMBtu)	Daily Available Oil Generation Minimum (MWh)	Daily Available Oil Generation Average (MWh)	Daily Available Oil Generation Largest Three Day Decline (MWh)
Infrequent Case					
Central Case	0	NA	6,753	11,656	(77)
No Fuel-Related Market Response					
Risk Premium x1.25	0	NA	6,753	11,656	(77)
Shock HQ 1 Day	0	NA	7,237	12,184	(46)
Shock HQ 5 Days	0	NA	6,569	12,068	2,228
High LNG Supply	0	NA	14,294	10,452	(4,307)
Low LNG Supply	0	NA	22,417	13,526	(9,127)
High Load	0	NA	14,520	12,955	(3,628)
Oil Retirements; Renewable Replacement	0	NA	14,728	12,037	(5,228)
Nuclear Retirements; Renewable Replacement	0	NA	8,562	11,244	(1,148)
With Fuel-Related Market Response					
Oil Retirements; Gas Replacement	0	NA	10,830	12,482	3,980
Oil Retirements; Gas / Dual Fuel Replacement	0	NA	30,811	14,288	(16,026)
Nuclear Retirements; Gas Replacement	0	NA	7,201	11,064	2,498
Nuclear Retirements; Gas / Dual Fuel Replacement	0	NA	35,900	16,738	(22,968)

2. *Scenarios Evaluating Alternate ESI Proposals*

a) Change in ESI Product Quantities

Several Alternate Proposals consider changes in the quantity of ESI products procured in the day-ahead market, including: No RER, No EIR/RER and RER Plus. Because the assumptions about market participant response differ in each of these Alternate Proposals, they each provide different information about ESI's expected impacts, though we note that the assumed levels of fuel inventory that these alternate ESI designs would incent under each Alternate Proposal are not precisely calibrated, and therefore should be interpreted with this understanding.

The RER Plus Case assumes an additional 600 MW of RER is procured beyond the 1200 MW assumed in the Central Case ESI runs. Compared to the Central Case ESI results, the additional RER increases payments by $99 million, $50 million and $16 million in the Frequent, Extended and Infrequent Cases, respectively. These estimates may overstate the true cost impacts, as no change in fuel-inventory response by market participants is assumed, and the procurement of additional RER (and its corresponding impact on resource revenues) may incent the procurement of additional fuel which will tend to reduce total costs.

Eliminating the RER or eliminating both the RER and the EIR produces lower ESI costs than in the Central Cases in most, but not all, Cases, reflecting the reduction in payments due to the lower quantity of ancillary services procured. This impact is (partially) offset by a reduction in incented energy inventory, which will tend to increase costs. With no RER, payments are reduced relative to the Central case by $73 million, $48 million and $9 million in the Frequent, Extended and Infrequent Cases relative to the ESI costs in the Central Cases, respectively. In the no RER/EIR, payments are reduced by $108 million and $29 million in the Frequent and Infrequent Cases, and increase by $83 million in the Extended Case relative to the ESI costs in the Central Cases. These outcomes reflect both the elimination of the EIR and RER products, which would tend to lower payments, and the reduction in energy supply incented by ESI, which would tend to increase LMPs and, in turn, increase payments. Differences in ESI's impact compared to the proposed ESI design reflects the net impact of these two effects.

With different assumed energy inventory response to ESI's incentives, the operational metrics differ from the Central Case. With No RER, which assumes a 50% reduction in the fuel incentive response to ESI, the operational metrics improve in 8 of 11 instances relative to CMR. Compared to ESI's reliability benefits in the Central Case, the reliability benefits appear more modest under these alternative ESI designs that do not procure RER, as this design change would reduce the incentive for resources to take actions to be available to provide energy in real-time.[62] With No RER/EIR, there is minimal change in these metrics compared to CMR, consistent with the assumption that such an alternative design does not incent any incremental fuel.

b) Change in Strike Price

The Strike Price + $10 Scenario assumes a strike price set at $10 above the level assumed in the Central Case, where the hourly strike price equals the expected RT LMP, based on the DA LMP. Compared to the

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[62] Note that there are four operational metrics, but for the Infrequent Case only three are relevant because one metric – natural gas system use under stressed market conditions – is not applicable due to low natural gas prices.

Central Case, total payments are reduced by $1 million, $15 million and $13 million in the Frequent, Extended and Infrequent Cases relative to the change in costs associated with the ESI Central Cases, respectively. These reductions reflect several effects. First, the total cost of the DA energy option procurement is reduced. Compared to the Central Case, the higher strike price reduces the average DA energy option price by $4.09 per MWh, $3.98 per MWh and $3.07 per MWh in the Frequent, Extended and Infrequent Cases, respectively. The lower option prices do not result in direct reductions in payments, however, because the gains in real-time settlement of these options are also reduced. Thus, in total, the higher strike price reduces the net cost of procuring the ESI products by $5 million, $7 million and $8 million in the Frequent, Extended and Infrequent Cases, respectively. Second, the cost for energy, reflecting LMPs and FER payments, also decreases in the Extended and Infrequent Case by $9 million and $5 million, respectively, while increasing by $2 million in the Frequent Case.

No change in energy inventories are assumed in this Case, thus the operational metrics do not meaningfully change compared to the Central Case. While our analysis does not quantify an impact to reliability benefits, we would nonetheless expect that ESI would create less reliability benefit because, with a reduced closeout cost risk under this Scenario relative to the ESI Central Cases, the incentives to increase inventoried energy would be diminished.[63]

3. *No Incremental Fuel under ESI*

We evaluate a Scenario in which we assume no incremental energy inventory under ESI, but otherwise keep all assumptions unchanged from the Central Case. We expect that ESI will incent incremental fuel (recall, **Section IV.A.1**. demonstrated that ESI appears likely to incent incremental oil in the Central Cases), but we provide this alternative Scenario as a means to better understand the impacts of ESI, independent of its effect on incentives to improve resource deliverability of energy in real-time.

Without incremental energy inventory, total payments are $398 million, $226 million and $40 million higher under ESI compared to the CMR Case. These higher consumer costs relative to the ESI Central Cases are largely driven by increased payments to DA energy, driven by FER payments. For example, in the Extended Case, the average FER price is $3.55 per MWh in the Central Case, which increases to $7.78 per MWh with no incremental fuel inventory, an increase of $4.23 per MWh. Furthermore, there is not a significant decrease in energy prices, as occurs in the ESI Central Cases, because these simulations do not assume the design incents incremental fuel relative to current market rules, which is the primary driver in the reduction in energy prices.

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[63] For further analysis and discussion, *see* ISO-New England, “Energy Security Improvements (ESI): Assessing a Strike Price ‘Bias’, How adding a ‘bias’ to the strike price may impact resource incentives,” NEPOOL Markets Committee, February 11-13, 2020, https://www.iso-ne.com/static-assets/documents/2020/02/a4_a_iv_esi_assessing_a_strike_price_bias.pptx.

Table 48. Scenarios Evaluating Alternate ESI Proposals - Prices & Payments, Winter Frequent Case

	Weighted Average Prices ($/MWh)			Customer Payment ($ Million)		
Scenario Name/Acronym	Change in DA LMP (ESI - CMR)	Average FER Price	Average Option Price (GCR, RER)	Change in Energy and Ancillary Services (+ FER in ESI) (ESI - CMR)	Energy Options (DA Cost Net of RT Settlement)	Change in Total Customer Payments
Frequent Case						
Central Case	($5.49)	$7.76	$27.00	$67	$66	$132
No Fuel-Related Market Response						
RER Plus	($5.37)	$9.48	$30.61	$126	$105	$231
Strike Plus $10	($5.41)	$7.76	$22.91	$69	$61	$131
With Fuel-Related Market Response						
No EIR/RER	$0.06	NA	$22.46	$3	$21	$24
No RER	($4.36)	$5.63	$22.92	$35	$25	$59
No Incremental Oil under ESI						
No Incremental Oil under ESI	($1.06)	$11.00	$29.87	$314	$84	$398

Table 49. Scenarios Evaluating Alternate ESI Proposals - Prices & Payments, Winter Extended Case

	Weighted Average Prices ($/MWh)			Customer Payment ($ Million)		
Scenario Name/Acronym	Change in DA LMP (ESI - CMR)	Average FER Price	Average Option Price (GCR, RER)	Change in Energy and Ancillary Services (+ FER in ESI) (ESI - CMR)	Energy Options (DA Cost Net of RT Settlement)	Change in Total Customer Payments
Extended Case						
Central Case	($6.43)	$3.55	$14.46	($100)	$32	($69)
No Fuel-Related Market Response						
RER Plus	($6.31)	$4.36	$16.17	($71)	$51	($19)
Strike Plus $10	($6.56)	$3.40	$10.48	($109)	$25	($84)
With Fuel-Related Market Response						
No EIR/RER	$0.21	NA	$11.43	$7	$7	$14
No RER	($5.83)	$2.28	$11.30	($122)	$6	($117)
No Incremental Oil under ESI						
No Incremental Oil under ESI	($2.39)	$7.78	$17.49	$166	$60	$226

Table 50. Scenarios Evaluating Alternate ESI Proposals - Prices & Payments, Winter Infrequent Case

	Weighted Average Prices ($/MWh)			Customer Payment ($ Million)		
Scenario Name/Acronym	Change in DA LMP (ESI - CMR)	Average FER Price	Average Option Price (GCR, RER)	Change in Energy and Ancillary Services (+ FER in ESI) (ESI - CMR)	Energy Options (DA Cost Net of RT Settlement)	Change in Total Customer Payments
Infrequent Case						
Central Case	($1.20)	$1.94	$5.75	$20	$15	$35
No Fuel-Related Market Response						
RER Plus	($1.53)	$2.44	$6.71	$25	$26	$51
Strike Plus $10	($0.85)	$1.35	$2.68	$15	$7	$22
With Fuel-Related Market Response						
No EIR/RER	($0.00)	NA	$5.01	($0)	$7	$6
No RER	($1.05)	$1.76	$5.04	$19	$7	$26
No Incremental Oil under ESI						
No Incremental Oil under ESI	($1.02)	$1.94	$5.77	$26	$15	$40

Table 51. Scenarios Evaluating Alternate ESI Proposals - Operational Metrics, Winter Frequent Case

Scenario Name/Acronym	Operating Reserve Shortages (Hours)	NG Used in Generation when NG Supply is Tight (MMBtu)	Daily Available Oil Generation Minimum (MWh)	Daily Available Oil Generation Average (MWh)	Daily Available Oil Generation Largest Three Day Decline (MWh)
Frequent Case					
Central Case	0	(2,897,177)	24,512	15,204	(16,413)
No Fuel-Related Market Response					
RER Plus	0	(2,909,342)	23,866	15,276	(16,538)
Strike Plus $10	0	(2,900,051)	24,432	15,203	(16,413)
With Fuel-Related Market Response					
No EIR/RER	0	3,314	68	(80)	920
No RER	0	(2,448,623)	20,954	11,281	(4,907)
No Incremental Oil under ESI					
No Incremental Oil under ESI	0	(1,326,266)	645	(1,185)	(2,183)

Table 52. Scenarios Evaluating Alternate ESI Proposals - Operational Metrics, Winter Extended Case

Scenario Name/Acronym	Operating Reserve Shortages (Hours)	NG Used in Generation when NG Supply is Tight (MMBtu)	Daily Available Oil Generation Minimum (MWh)	Daily Available Oil Generation Average (MWh)	Daily Available Oil Generation Largest Three Day Decline (MWh)
Extended Case					
Central Case	0	(943,020)	32,663	14,022	(7,527)
No Fuel-Related Market Response					
RER Plus	0	(943,020)	32,663	14,017	(7,527)
Strike Plus $10	0	(943,020)	32,663	14,022	(7,527)
With Fuel-Related Market Response					
No EIR/RER	0	0	0	45	0
No RER	0	(860,078)	35,039	11,597	(7,585)
No Incremental Oil under ESI					
No Incremental Oil under ESI	0	(739,566)	3,017	(90)	(247)

Table 53**. Scenarios Evaluating Alternate ESI Proposals - Operational Metrics, Winter Infrequent Case**

Scenario Name/Acronym	Operating Reserve Shortages (Hours)	NG Used in Generation when NG Supply is Tight (MMBtu)	Daily Available Oil Generation Minimum (MWh)	Daily Available Oil Generation Average (MWh)	Daily Available Oil Generation Largest Three Day Decline (MWh)
Infrequent Case					
Central Case	0	NA	6,753	11,656	(77)
No Fuel-Related Market Response					
RER Plus	0	NA	6,753	11,656	(77)
Strike Plus $10	0	NA	6,753	11,656	(77)
With Fuel-Related Market Response					
No EIR/RER	0	NA	0	0	0
No RER	0	NA	5,896	6,609	(416)
No Incremental Oil under ESI					
No Incremental Oil under ESI	0	NA	0	0	(0)

4. Non-Winter Scenarios

Two non-winter scenarios evaluate alternate ESI proposals, with one assuming no RER product and the other assuming a strike price set $10 per MWh above the expected RT prices for each hour. Compared to the Central Case, both Alternate ESI Proposals result in lower total payments. With no RER, total payments increases are $48 million and $56 million in the Moderate and Severe Cases, respectively. These payment increases are $41 million and $69 million lower than the corresponding payment increases associated with ESI in the Central Case. These reductions are driven in roughly equal proportion by lower FER payments and reduced net payments for DA energy options.

Increasing the strike price by $10 per MWh also results in lower payments. Compared to the Central Case, both Scenarios results in lower total payments. With a $10 strike price adder, total payment increases are $70 million and $107 million in the Moderate and Severe Cases, respectively. These payments are $19 million and $18 million lower than the corresponding payments in the Central Case. These reductions occur mostly from smaller net payments for DA energy options, which are $15 million and $14 million lower in the Moderate and Severe Cases, respectively. These results are presented in **Table 50** and **Table 51** below.

Table 54. Non-Winter Alternate ESI Proposals - LMPs & Payments, Non-Winter Severe Case

	Weighted Average Prices ($/MWh)			Customer Payment ($ Million)		
Scenario Name/Acronym	Change in DA LMP (ESI - CMR)	Average FER Price	Average Option Price (GCR, RER)	Change in Energy and Ancillary Services (+ FER in ESI) (ESI - CMR)	Energy Options (DA Cost Net of RT Settlement)	Change in Total Customer Payments
Severe Case						
Central Case	($0.23)	$1.12	$7.80	$78	$47	$125
Severe Case - ESI Design Scenario						
Strike Price Plus $10	($0.22)	$1.06	$4.74	$74	$33	$107
No RER	($0.26)	$0.82	$6.21	$47	$8	$56

Table 55. Non-Winter Alternate ESI Proposals - LMPs & Payments, Non-Winter Moderate Case

	Weighted Average Prices ($/MWh)			Customer Payment ($ Million)		
Scenario Name/Acronym	Change in DA LMP (ESI - CMR)	Average FER Price	Average Option Price (GCR, RER)	Change in Energy and Ancillary Services (+ FER in ESI) (ESI - CMR)	Energy Options (DA Cost Net of RT Settlement)	Change in Total Customer Payments
Moderate Case						
Central Case	($0.18)	$0.76	$6.35	$50	$38	$89
Moderate Case - ESI Design Scenario						
Strike Price Plus $10	($0.14)	$0.68	$3.37	$47	$23	$70
No RER	($0.22)	$0.59	$5.67	$31	$16	$48

D. Conclusions Regarding Energy Security Improvements Impacts

The results of the Scenario analysis are generally consistent with and support the conclusions developed in the more detailed review of the Central Case. ESI would be expected to increase incentives for resources to maintain more secure energy supplies and generally improve resources' ability to deliver energy supplies in real-time, through the combination of FER payments and the opportunity to sell DA energy options by supplying the new day-ahead ancillary services created by ESI. These impacts are observed through the strong FER and ESI ancillary service price signals created across Scenarios. These day-ahead new ancillary service opportunities would compensate resources for providing energy security even if they do not supply DA energy, thus increasing incentives to preserve existing energy inventories. These changes would drive reliability benefits and are captured in our analysis through the improvements in fuel system operational outcomes that are indicative of improved reliability. In addition, ESI would be expected to improve efficiency and lower production costs under stressed market conditions when the increase in energy inventory reduces energy production from less efficient suppliers and higher cost fuels.

The analysis also shows that ESI would be expected to increase aggregate payments by load (to suppliers) during periods when stressed market conditions are uncommon or infrequent (as indicated by winter Infrequent Case results and non-winter Moderate Case results). However, under stressed market conditions, total payments by load (to suppliers) could increase or decrease depending on a number of factors, including the nature of the stressed market conditions and the amount of incremental energy inventory incented by ESI.

Under some Scenarios, these incentives and payment impacts become more sensitive to market conditions, including aggregate fuel market supplies and the response of market participants to improve real-time energy deliverability.

V. Appendices

A. Additional Production Cost Model Details

1. *Mathematical Optimizer Specification*

This section summarizes the market-clearing mechanisms as implemented within the production cost model. It provides a mathematical description of the design of the day-ahead (DA) market under current market rules (CMR) and under the proposed Energy Security Improvements (ESI), and the real-time (RT) market.

a) General notation

<u>Indices</u>

i: participant

t: hour

<u>Continuous variables</u>

$g_{i,t}$: DA energy supply, including physical and virtual supply

$d_{i,t}$: DA bid-in demand, including physical and virtual demand

$r_{i,t}^{Reserve10}, r_{i,t}^{Reserve30}$: operating reserves 10 and 30-minute supply

D_t: RT cleared demand (based on scaled historical data)

<u>Parameters</u>

$c_{i,t}(\cdot)$: DA energy offer

$b_{j,t}(\cdot)$: DA demand bid

b) Model-specific notation

<u>Continuous variables</u>

$o_{i,t}^{EIR}$: EIR option quantity

$o_{i,t}^{GCR10}, o_{i,t}^{GCR30}$: GCR10, GCR30 option quantities

$o_{i,t}^{RER}$: RER option quantity

<u>Parameters</u>

L_t^{DA}: load forecast

$c_{i,t}^{EIR}(\cdot)$: EIR option offer

$c_{i,t}^{GCR10}(\cdot), c_{i,t}^{GCR30}(\cdot)$: GCR10 and GCR30 option offers

$Req_t^{GCR10}, Req_t^{GCR30}$: GCR10 and GCR30 option requirements

$c_{i,t}^{RER}(\cdot)$: RER option offers

Req_t^{RER}: RER option requirements

$Req_t^{Reserve1}$, $Req_t^{Reserve30}$: operating reserve 10 and 30 minute requirements

c) Market Price and Equilibrium under ESI

Market prices:[64]

- **DA LMP =** λ_t^{DA}, paid to physical and virtual supply
- **EIR/FER price =** γ_t, paid to physical supply, including physical energy supply and physical supply providing DA energy options for EIR, but not energy
- **GCGCR10, GCR30, RER prices =** τ_t^*, paid to generators supplying DA energy option for GCR or RER
- **RT LMP =** λ_t^{RT}, paid to generators
- **RT Operating Reserve prices =** $\tau_t^{Reserve*}$, paid to generators supplying reserves, but not energy; paid by RT load

d) Current Day-Ahead Market (CMR)

Objective function

$$\min \sum_i \sum_t [c_{i,t}(g_{i,t}) - b_{i,t}(d_{i,t})]$$

Constraints

1. DA financial energy balance constraint: For all t,

$$\sum_i (g_{i,t} - d_{i,t}) = 0 \qquad (\lambda_t^{DA} \text{ free})$$

2. DA financial capability constraint (physical generators): For all i, t,

$$g_{i,t} \leq EcoMax_i \qquad (\alpha_{i,t}^{total} \geq 0)$$

e) Proposed Day-Ahead Market with ESI

ESI imposes three new constraints: an FER requirement, satisfied through EIR, to cover the gap (if any) between the hourly DA load forecast and the supply of physical energy cleared in the day-ahead market, GCR requirements to secure RT operating reserves in advance of the operating day, and an RER requirement to secure sufficient energy is available to cover a large, unexpected contingency.

64 We only specify which types of resources receive each type of payment (price), recognizing that there are corresponding differences in payments made by different types of resources. However, as the analysis will only consider aggregate payments by load to physical supply, we do not analyze cost allocation across different load serving entities.

Objective function

$$\min \sum_i \sum_t \left[c_{i,t}(g_{i,t}) - b_{i,t}(d_{i,t}) + c_{i,t}^{EIR}(o_{i,t}^{EIR}) + c_{i,t}^{GCR10}(o_{i,t}^{GCR10}) + c_{i,t}^{GCR30}(o_{i,t}^{GCR30}) + c_{i,t}^{RER}(o_{i,t}^{RER})\right]$$

Constraints

1. DA financial energy balance constraint: For all t,

   A. $\sum_i (g_{i,t} - d_{i,t}) = 0$ $\quad (\lambda_t^{DA} \text{ free})$

2. DA financial capability constraint (physical generators): For all i, t,

   $g_{i,t} \leq EcoMax_i$ $\quad (\alpha_{i,t}^{total} \geq 0)$

3. FER constraints, satisfied through EIR: for all t,

   $\sum_i g_{i,t} + \sum_i o_{i,t}^{EIR} \geq L_t^{DA}$ $\quad (\gamma_t \ \geq 0, \text{free})$

4. GCR and RER constraint: for all t,

   $\sum_i o_{i,t}^{GCR10} \geq Req_t^{GCR10}$ $\quad (\tau_t^{GCR10} \geq 0, \text{free})$

   $\sum_i (o_{i,t}^{GCR10} + o_{i,t}^{GCR30}) \geq Req_t^{GCR30}$ $\quad (\tau_t^{GCR30} \geq 0, \text{free})$

   $\sum_i (o_{i,t}^{GCR10} + o_{i,t}^{GCR30} + o_{i,t}^{RER}) \geq Req_t^{RER}$ $\quad (\tau_t^{RER} \geq 0,, \text{free})$

f) Real-Time Market

Objective function

$$\min \sum_i \sum_t \left[c_{i,t}(g_{i,t})\right]$$

Constraints

1. DA financial energy balance constraint: For all t,

   B. $\sum_i (g_{i,t}) = D_T$ $\quad (\lambda_t^{RT} \text{ free})$

2. RT Operating Reserve constraint: for all t,

   $\sum_i r_{i,t}^{Reserve10} \geq Req_t^{Reserve10}$ $\quad (\tau_t^{Reserve10} \geq 0, \text{free})$

   $\sum_i (r_{i,t}^{Reserve10} + r_{i,t}^{Reserve30}) \geq Req_t^{Reserve30}$ $\quad (\tau_t^{Reserve30} \geq 0, \text{free})$

2. Opportunity Cost Adder

Opportunity costs reflect foregone revenues of providing energy today rather than the future for resources with limited fuel inventories. As of December 2018, ISO-NE changed market mitigation procedures to provide automated calculation of opportunity costs that allows oil-only and dual-fuel resources to facilitate inclusion of these costs in their market offers. The model calculated opportunity cost bid adders for oil-fired resources in order to maximize oil resource's likelihood of providing energy during its most profitable hours over a 3-day period, as described below.

First, LMPs are forecasted over a 3-day period by solving a 3-day-ahead market. Each oil resource is assumed to begin the 3-day period with a full tank. This provides a conservative (smaller) estimate of the opportunity costs compared to an estimate based on a longer time period. Second, oil resources determine their projected net revenues in each hour over the 3-day period based on expected LMPs and their marginal costs. Third, oil units determine their opportunity cost bid adder such that they would only provide energy during the most profitable hours given expected LMPs.

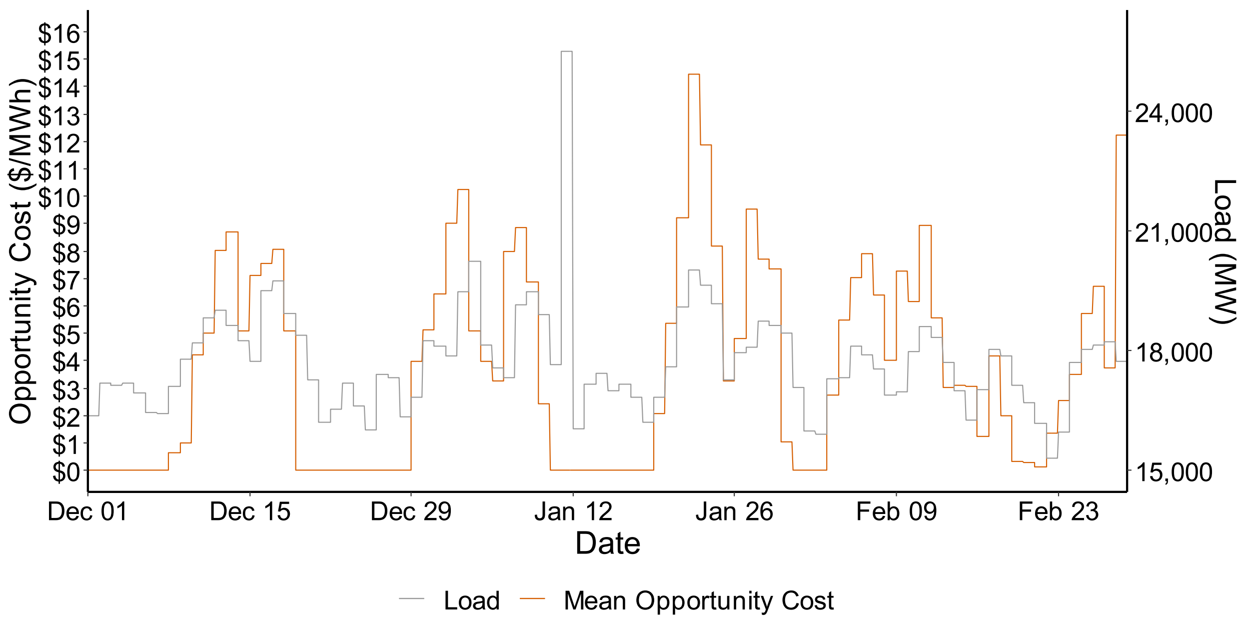
In the illustrative example shown in **Table 56**, an oil resource ranks each hour of expected net revenues from highest to lowest. If this oil resource currently has 9 hours of oil inventory, the resource will set its opportunity cost bid adder equal to the net revenues in its 10th most profitable hour, or $9.04 per MWh. This opportunity cost bid adder would help to ensure that the oil resource would only provide energy during the 9 most profitable hours.

Table 56. Illustrative Oil Hourly Net Revenue

Hour	Bid ($/MWh) [A]	Expected LMP ($/MWh) [B]	Expected Net Revenues ($/MWh) [C]=[B]-[A]	Expected Net Revenues (Rank)
41	$100.69	$117.11	$16.42	1
42	$100.69	$116.46	$15.77	2
43	$100.69	$116.42	$15.73	3
8	$100.69	$115.75	$15.06	4
9	$100.69	$115.43	$14.74	5
40	$100.69	$115.31	$14.62	6
7	$100.69	$114.58	$13.89	7
10	$100.69	$113.20	$12.51	8
11	$100.69	$111.34	$10.65	9
12	**$100.69**	**$109.73**	**$9.04**	**10**
18	$100.69	$108.34	$7.65	11
19	$100.69	$107.98	$7.29	12
37	$100.69	$104.55	$3.86	13
36	$100.69	$104.04	$3.35	14

During periods when oil-fired resources are uncompetitive (i.e., negative expected net revenues) or have large oil inventories, oil-fired resources will have no opportunity costs. Positive opportunity costs tend to occur during periods with high load, high natural gas prices, and limited fuel inventories (e.g., after a prior cold spell). **Figure 32** shows the relationship between daily peak load and opportunity costs for the Frequent Case. Positive opportunity costs tend to overlap with periods of high daily peak loads and increase in magnitude (relative to load) as oil inventories are depleted throughout the winter. Opportunity costs can cause shifts in the timing of supply from energy-limited resources, causing them to supply energy at a later point in time than they otherwise would have without opportunity costs.

Figure 32. Day-Ahead Daily Peak Load and Opportunity Costs, Winter Central Frequent Case



3. Demand Bid Calibration

The demand curves used within the PCM are constructed hourly for the day-ahead market based on historical bids from the relevant historical period for a given scenario. Demand curves are constructed in four stages:

First, historical physical demand, virtual demand (DECs) and virtual supply (INCs) are separated into price buckets and netted against each other to create an aggregate, stepped demand curve.

Second, historical bid quantities are scaled to account for the difference between historical and projected future load levels. An hourly future load quantity is first calculated based on the forecast peak and total energy as reported in the ISO-NE Forecast Report of Capacity, Energy, Loads, and Transmission (CELT 2019).[65] (see **Section III.B.1**). Then, historical bid quantities are scaled by the ratio of future load quantities to historic load quantities.

Third, historical demand bid prices are scaled to future DA LMPs as estimated by the PCM. These changes are driven from a variety of factors, such as assumptions regarding the resource fleet. Future DA LMPs are first calculated by running a version of the day-ahead market with fixed hourly future loads and current market

[65] ISO New England. (2018, September 5). 2018-2027 Forecast Report of Capacity, Energy, Loads and Transmission. Retrieved from https://www.iso-ne.com/system-planning/system-plans-studies/celt/ (ISO New England, 2018)

rules (no ESI products). Demand bid prices are then scaled by the ratio of these calculated future DA LMPs to historical DA LMPs.

A fourth step is used only in cases modeling EIR. This step accounts for arbitrage opportunities between DA and RT LMPs. As described in **Section III.B.5**, all else equal, DA LMPs will tend to be lower under ESI due to the substitutions between DA energy and EIR. This would lead to divergence between DA and RT LMPs, introducing an arbitrage opportunity. To capture the market's response to this opportunity, demand is increased (i.e., demand curves are shifted to the right) under ESI so that DA LMPs align with expected RT LMPs.

B. Resource Data and Assumptions

This section details the data sources, model assumptions, and methodology used to evaluate the impacts of ESI on energy market outcomes.

1. Electricity Market

Energy suppliers are modeled either as individual (discrete) resources to be optimized by the production cost model, or profiles that are netted off from load, reserve, or DA energy option requirements. This section outlines how the resource characteristics and supply amounts (for profiled resources) are determined.

a) Central Case Resources and Retirements

The electricity supply for winter (2025-26) and non-winter (2026) Cases includes all generators that cleared ISO-NE's thirteenth Forward Capacity Auction (FCA 13) on February 4, 2019 for the Capacity Commitment Period of June 1, 2022 to May 31, 2023. These resources are carried forward into future scenarios unless otherwise removed for specific scenarios. In addition to these FCA-cleared units, future supply includes 886 MW of new solar capability, 458 MW of battery storage, and 1,339 MW of wind capability (507 MW onshore, 832 MW offshore).[66] These additions are based on the 10-year projections in ISO-NE's CELT 2019. **Table 4** in the body of this report shows electricity capacity assumptions by resource type under current market rules and ESI.[67]

We assume a number of resource retirements for all scenarios, based on the FCA 13 retirement de-list bids, in addition to retirements that are based on specifications provided by ISO-NE.[68] We also assume the retirement of the Mystic 8 and 9 generating facility, which is subject to a cost-of-service agreement to operate through May of 2024.

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66 New capacity from Generator List with Existing and Expected Seasonal Claimed Capability, S&P Global Market Intelligence. Additional capacity is compared with existing capacity in August 2019. Offshore generation capability derived from nameplate capacity and historical generation values from Vineyard Wind.

67 Under ESI, electricity supply also includes an additional 616 MW of generation sourced from liquefied natural gas.

68 These additional retirements are based on correspondence with ISO New England staff.

Table 57. Assumed Retirements

Resource	Non-Winter Capacity (MW)	Winter Capacity (MW)
Gas Combined Cycle	1,413	1,700
Nuclear Steam	677	683
Gas/Oil Steam	575	560
Coal Steam	383	385
Gas/Oil Combined Cycle	54	57
Oil Combustion (Gas) Turbine	30	41
Bio/Refuse	11	16
Hydro (Daily Cycle - Run Of River)	4	10
Oil Internal Combustion	8	8
Hydro (Weekly Cycle)	2	2
Total	**3,158**	**3,464**

b) Discretely Modeled Resource Characteristics

Optimized resources include coal, dual-fuel, fuel cell, gas-only, oil-only, nuclear, biomass and refuse, price responsive demand (active demand response), and imports. Biomass, price responsive demand, and imports are modeled as aggregated units. All other resource types are modeled as individual units based on unit-specific ISO-NE and SNL data.

Individual resources are modeled based on unit-specific characteristics, including capacity, heat rate, emissions rates, variable costs, and fuel storage capabilities. These capabilities are used within the Production Cost Model to optimize total production cost and meet reserve requirements over the modeling periods. Unit-level characteristics are specific to each modeled generating unit, do not vary across hours, but do vary seasonally in the winter, summer, and shoulder seasons based on expected capacity and outage rates.

Unit capacity is based on the winter SCC in the winter and Expected Summer Peak SCC in the non-winter. EFORd is modeled as a percentage decrement in capacity (in all hours) and based on plant specific seasonal EFORd rates in the winter and summer (June 1st to August 31st). In the shoulder season (March 1st to May 31st and October 1st to November 30th), the outage rate is based on a fleet average of 18% and is applied to all plants equally.[69] Heat rates, allowance costs, non-fuel variable O&M costs, and non-fuel non-allowance variable O&M costs are taken from SNL, or, when missing, averaged by fuel type for dispatchable units.

[69] In September, the outage rate is based on a fleet average for September of 12% and is applied equally as well. This month was split apart to adjust more readily for historically high loads in this month, during which resources would have been less likely to undergo unforced maintenance. For shoulder seasons, the outage rate was based on the publically available information in ISO-NE's morning report. This outage rate is "the sum of capability of all generation scheduled Out of Service (OOS), forced OOS, or reduced for the day, as known at the time of Morning Report development for the peak hour of the day," available under "Generation Outages and Reductions" at https://www.iso-ne.com/markets-operations/system-forecast-status/morning-report/.

i) Biomass and Price Responsive Demand

Biomass and refuse quantity and offers (i.e., marginal costs) are modeled in segments based on historical generation and day-ahead offers from wood and municipal solid waste plants for winters 2013/14 through 2017/18. The historical MW offers are used to generate a supply curve for plants.

ISO-NE implemented Price Responsive Demand effective July 1, 2018. Price Responsive Demand quantity and offers are modeled in three segments based on historical day-ahead offers.

ii) Imports

Imports are modeled as individual generating units similar to biomass and active demand response with prices dependent on capacity. The model includes the following interconnections: Northport-Norwalk (Northpoint connection point), Cross-Sound Cable (Salisbury connection point), New York-New England Northern AC (Roseton and Shoreham connection points), and Hydro Quebec Phase I/II. Offers and capacity are determined using hourly transaction data from ISO-NE beginning June 1, 2012 and ending May 31, 2018. Import offers for all interconnections, excluding Roseton, are set at the mean of observed real-time hourly imports in MW. Import offers for Roseton are the mean of real-time hourly imports segmented by $20 per MWh price bins between $0 and $100 per MWh. The Roseton price bins reflect a supply curve observed in the historical data. Hourly data for Northport-Norwalk, Cross-Sound Cable, Hydro Quebec Phase I/II, and the Shoreham connection point of New York-New England Northern AC did not show meaningful price-supply relationships.

c) Hourly Profiled Resource Characteristics

i) Solar, Wind, and Hydroelectric

Unit characteristics for solar, wind, and hydroelectric power are derived from the generator list reported in CELT 2019 and cleared in FCA 13.[70] Future hourly generation for renewable and hydroelectric units is based on historical hourly generation in the winter or non-winter scenario and scaled by the historical capacity's share of the assumed future capacity. Scaled resources include on-shore wind, photovoltaic solar, run-of-river, and pondage hydroelectric power. Hourly power generation is based on historical data received from ISO-NE.

ii) Pumped Storage and Battery Storage

Future generation for pumped storage units is based on a 24-hour generation profile received from ISO-NE that is scaled proportionally to capacity in each hour. The storage profiles model pumping or charging as extra demand. To model round-trip efficiency for storage units, energy consumed during pumping or charging exceeds energy produced.

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70 ISO New England. (2018, September 5). 2018-2027 Forecast Report of Capacity, Energy, Loads and Transmission. Retrieved from https://www.iso-ne.com/system-planning/system-plans-studies/celt/

iii) Off-Shore Wind

Unit characteristics for off-shore wind are derived from modeled hourly generation data received from ISO-NE that is based upon offshore meteorological buoy wind speed data.

d) Real-Time Reserve Provision

Real-time operating reserves are modeled for 10-minute and 30-minute operating reserve products. We do not model separate spin and non-spin 10-minute reserves, but rather model a single 10-minute product.

Offline reserve capabilities are based on historical analysis of Claim 10 and Claim 30 audit data. Claim 10 and Claim 30 capabilities for dispatchable generation (oil, gas, coal, and dual-fuel) are based on the weekly Claim 10 and Claim 30 Capability report generated by ISO-NE over the period from December 1, 2018 through February 28, 2019. Offline reserve capabilities are constant over a winter. For the non-winter period, the offline reserve capability is calculated between March 1, 2019 and October 1, 2019.

Dispatchable hydroelectric power reserve capabilities are profiled from hourly averages of five-minute data from June 1, 2012 through December 31, 2018 on 10-minute operating reserves, 10-minute spinning reserves, and 30-minute spinning reserves. The future reserve profile for hydroelectric units is based on the hourly data in the specific winter or non-winter scenario and scaled by the historical capacity's share of the assumed future capacity.

e) Day-Ahead Energy Option Provision

The model assumes that oil, gas, dual-fuel, coal, run of river hydro, weekly hydro, pond hydro, and pumped storage are able to provide day-ahead energy options. For resources not modeled as profiles (as explained in **Section V.B.1.b**. above), resources provide GCR10, GCR30, EIR, and RER240 based on measures of offline reserve capability (for resources supplying from a cold start) or ramp capability (for resources that must be on-line to supply reserves).

Resources able to provide day-ahead energy options from a cold start are combustion turbines and internal combustion engines. GCR10 and GCR30 capabilities are based on historical Claim 10 and Claim 30 data provided by ISO-NE. EIR and RER240 capabilities are based on modeled Claim 60 (for EIR) and Claim 240 (for RER) values modeled and provided by ISO-NE.[71]

Resources able to provide day-ahead energy options only when also providing energy are combined cycle, steam, and coal units. These units must be supplying energy in order to be cleared by the production cost model for day-ahead energy options. The capability of these resources to provide day-ahead energy options is based on ramp rate data provided from ISO-NE.

Resources that are modeled as profiles can provide GCR10, GCR30 or RER240 based on historic levels of real-time operating reserves (see **Section V.B.1.c**., above). Resources are assumed to provide day-ahead

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[71] For more information, see Ewing, Ben, "Energy Security Improvements: Market-Based Approaches," January 13-15, 2020. https://www.iso-ne.com/static-assets/documents/2020/01/a5_a_iii_esi_replacement_energy_reserves_rev1.pptx.

energy options in equivalent quantities to historic operating reserve levels. Generally, these resources provide GCR10 and GCR30. In some rare hours, where historic operating reserves exceed the GCR requirements, these resources are modeled to provide RER.

2. Fuel and Emission Prices

a) Natural Gas

Projected natural gas prices take Algonquin City Gate daily spot prices from winters 2013-14, 2016-17, and 2017-18 in dollars per MMBtu.[72] While the model forecasts hourly gas constraints using historical inventory and deviation from heating degree day, projected gas prices are unadjusted from the daily base year price and are constant over the 24 hours of a gas-day. **Figure 33** shows the prices for natural gas and other fuels used in the winter months, while **Figure 34** shows these prices for the non-winter months.

b) LNG

Natural gas units with a forward LNG contract exercise calls on these supplies when the Algonquin spot price exceeds a trigger price, set to $16 per MMBtu. When exercised, these supplies have a production cost of $10 per MMBtu, which is the commodity price under the assumed contract. The trigger price exceeds the commodity price to account for the opportunity cost of each call, as the contract only provides for 10 days of supply and exercising calls when prices are too low would limit the opportunity to exercise on days when the price could be higher.

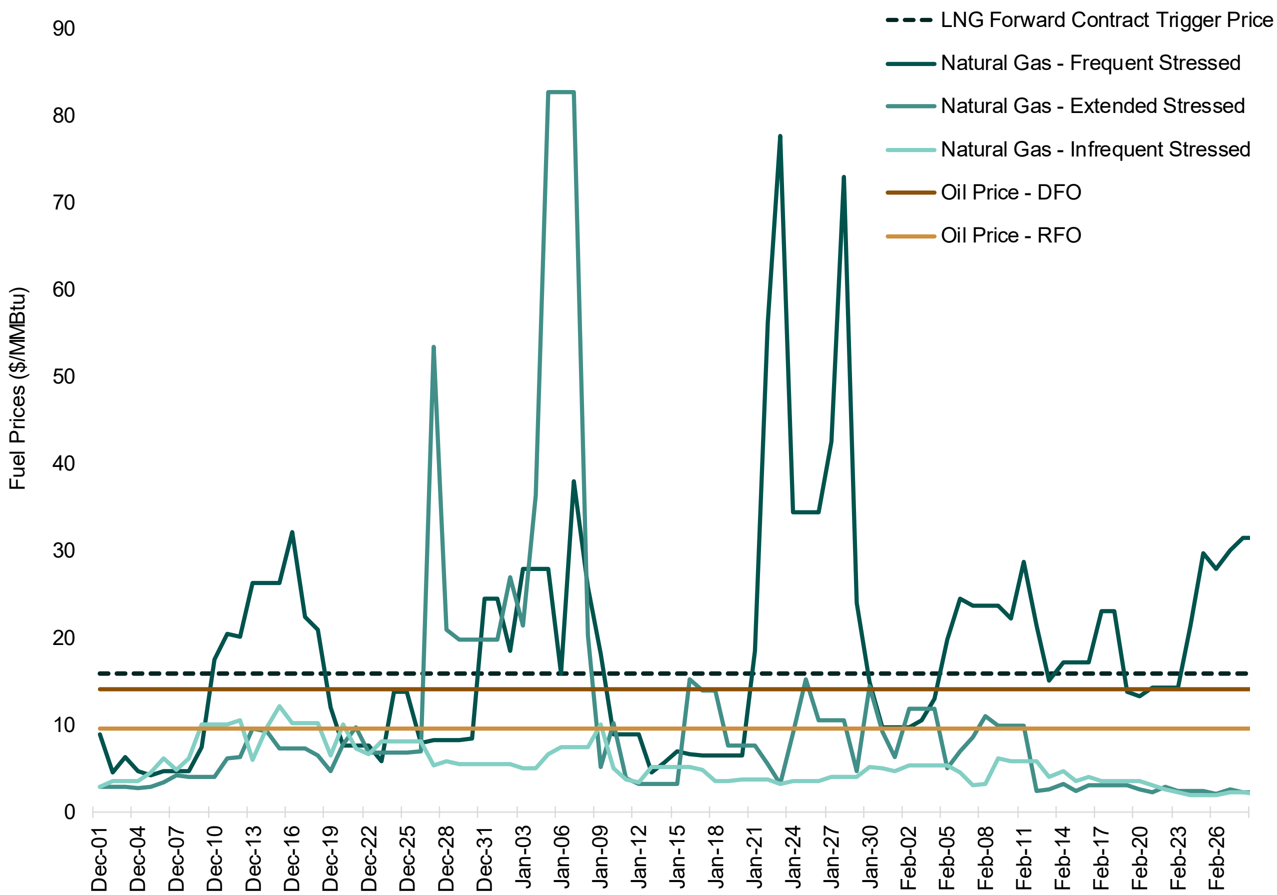
c) Oil

Units which use oil for their primary or secondary fuel may use 1) distillate fuel oil (DFO), 2) residual fuel oil (RFO), 3) jet fuel, or 4) kerosene. Forecasted prices use the December 2021 futures prices for each oil type: New York Harbor Heating Oil Futures NYMEX, New York Harbor Residual Fuel Oil 1.0% Sulfur futures, and Gulf Coast Jet Fuel (Platts) Futures Quotes for jet fuel and kerosene.[73] These fuel prices are fixed across all hours in both winter and non-winter Cases. Figures 3a and 3b show fuel prices for natural gas over the three winter severities and two non-winter severities, the LNG contract trigger price, and DFO and RFO oil.

72 Source data year depends on winter severity. Algonquin City Gate prices from S&P Global Market Intelligence.

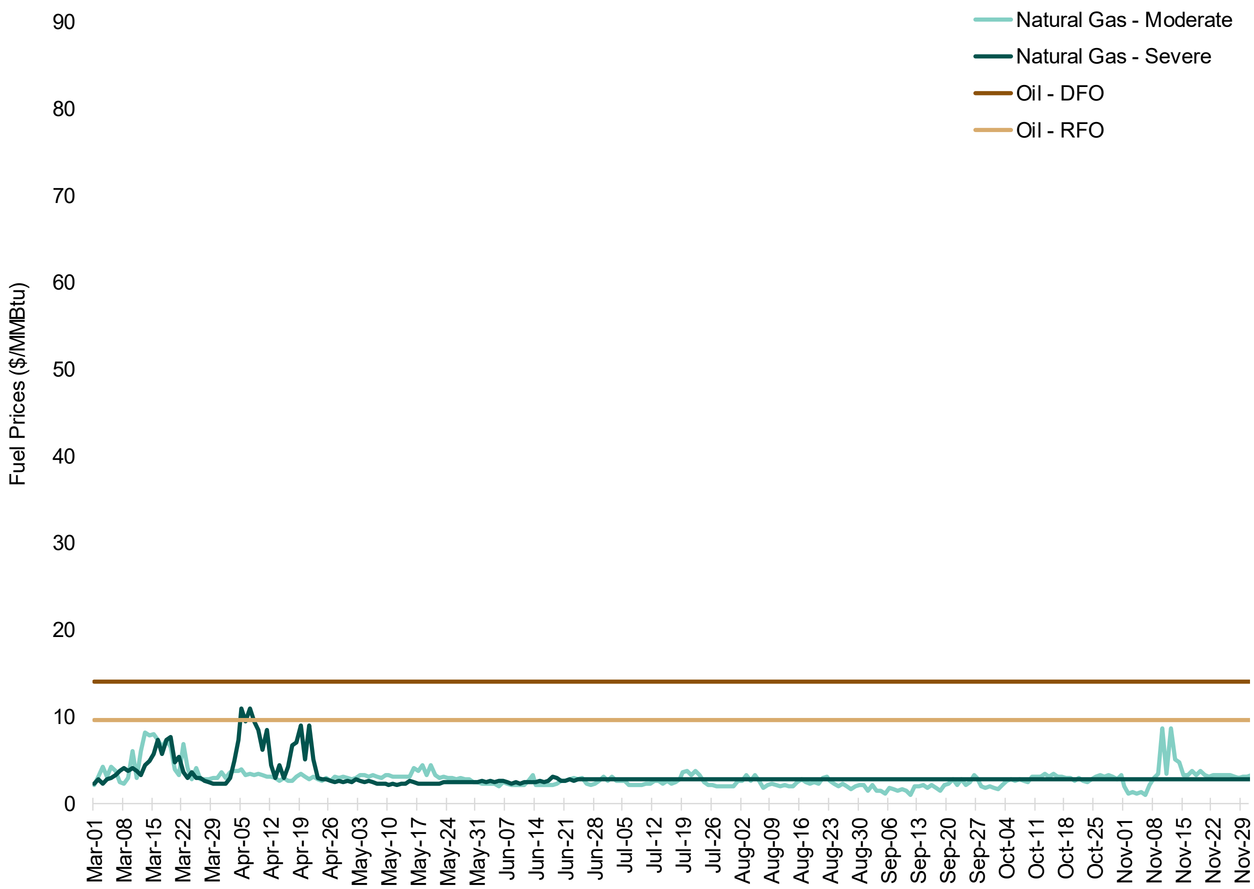
73 December 2021 was selected due to observed trading activity and market liquidity.

Figure 33. Future Fuel Prices by Winter Case ($ per MMBtu)[74]



[74] The Algonquin Natural Gas Price series is based on 2013/14, 2016/17, and 2017/18 prices for frequent, infrequent, and extended stressed conditions, respectively. The LNG Forward Contract Trigger Price is $16 per MMBtu, which indicates a resource would exercise the LNG Forward Contract whenever the price of Natural Gas rises above $16 per MMBtu. The modeled LNG contract is a forward contract with 10 calls, where one call is reserved to supply DA energy options. The commodity charge under an LNG Forward Contracts is $10 per MMBtu. The DFO - Oil price is $14.06 per MMBtu ($81.27 per BBL), based on December 2021 Futures. The RFO - Oil price is $9.64 per MMBtu ($60.58 per BBL), based on December 2021 Futures.

Figure 34. Future Fuel Prices by Non-Winter Case ($ per MMBtu)[75]



d) Coal

Coal prices are quarterly and based on shipments to the electric power sector by state from the Energy Information Administration.[76]

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[75] The Algonquin Natural Gas Price series is based on 2017 and 2018 prices for the moderate and severe non-winter conditions, respectively. The LNG Forward Contract Trigger Price is $16 per MMBtu, which indicates a resource would exercise the LNG Forward Contract whenever the price of Natural Gas rises above $16 per MMBtu. The modeled LNG contract is a forward contract with 10 calls, where one call is reserved to supply DA energy options. The commodity charge under an LNG Forward Contracts is $10 per MMBtu. The DFO - Oil price is $14.06 per MMBtu ($81.27 per BBL), based on December 2021 Futures. The RFO - Oil price is $9.64 per MMBtu ($60.58 per BBL), based on December 2021 Futures.

[76] U.S. Energy Information Administration - EIA - Independent Statistics and Analysis. Retrieved from https://www.eia.gov/coal/data/browser/#/topic/45?agg=1,0&geo=8&rank=g&freq=Q&rtype=s&pin=&rse=0&maptype=0&ltype=pin&ctype=map&end=201802&start=200801

e) Emissions

Emission costs include costs per ton of emitted CO_2, SO_2, and NOx. As with fuel prices, the production cost model assumes fixed allowance prices to capture the cost of environmental emission requirements. Thus, the model does not endogenously solve for market-clearing allowance prices needed to comply with aggregate, quantity-based limits (e.g., emission caps) imposed by certain environmental requirements, given production decisions across the entire year.

The CO_2 emissions price for each fuel type is the clearing price from the Regional Greenhouse Gas Initiative of New England and Mid-Atlantic States of the US (RGGI) 43rd auction held on March 13, 2019.[77] We do not model allowance prices, holdings, or acquisitions and do not distinguish by "regulated entities." All units are assumed to take the RGGI price as the price for their CO_2 emissions. Emissions prices for SO_2 are derived from annual allowances of SO_2 acid rain and take the May 2019 forward price for winter and non-winter months.[78] Emissions prices for NOx are derived from annual allowances from the US Environmental Protection Agency Cross-State Air Pollution Rules and take the May 2019 forward price for winter and non-winter months.[79] Total emissions for each emission type reflect a combination of factors, including the quantity of each type of fuel consumed. **Table 58** provides total winter fuel consumption by fuel type for each Central Case.

Table 58. Total Fuel Consumption by Fuel Type, Winter Central Case

Case		Total		
		Natural Gas (MMBTU)	Oil (BBL)	Coal (MMBTU)
Frequent Case	CMR	48,779,867	8,435,575	11,973,792
	ESI	46,726,510	8,738,681	11,973,792
Extended Case	CMR	70,954,852	3,925,122	8,030,226
	ESI	70,924,801	3,856,651	8,030,226
Infrequent Case	CMR	83,546,079	1,318,809	6,849,625
	ESI	83,546,079	1,314,057	6,849,625

By assuming allowance prices consistent with current market transactions, we intend to simulate market outcomes broadly consistent with these limits and, to the extent that results are inconsistent with these requirements, can test whether such differences have a material impact on the efficacy of the ESI proposal or the conclusions we draw from our analysis. Within New England, one important regulation with an annual aggregate cap is the Massachusetts CO_2 emission cap, which would cap emissions from Massachusetts' generation facilities at approximately 7.38 MT in 2025.[80] As shown in **Table 59**, our analysis finds that, with the assumed emission allowance prices of $9.67 per MT in 2025/26, that total emissions would exceed that

[77] Elements of RGGI. Retrieved from https://www.rggi.org/program-overview-and-design/elements

[78] S&P Global Market Intelligence for Acid Rain Annual SO_2 Allowances.

[79] S&P Global Market Intelligence for Annual Cross-State Air Pollution (CSAPR) NOx Allowances.

[80] ISO New England. (2017, September 26). Greenhouse Gas Regulatory Update. Retrieved from https://www.iso-ne.com/static-assets/documents/2017/09/ghgupdate_20170926.pdf

amount in all combinations of winter and non-winter month Cases. To test the sensitivity of this result to a higher emission allowance price that could be consistent with a lower MA emission quantity, we assume the Massachusetts' CO_2 emission allowance price is $14.67 per MT, which is $5 per MT higher than Central Case.[81] These tests find that Massachusetts' CO_2 emissions are reduced in all cases, and for some combinations of winter and non-winter Cases are below the cap. Moreover, aggregate changes in ESI impacts are relatively similar to our Central Case; for example, total payments change by small amounts in the Extended and Infrequent Cases, and are reduced by $11 million (from $132 million to $121 million) in the Frequent Case.

Table 59. Massachusetts Annual CO_2 Emissions

Non-Winter Case		Severe			Moderate		
Winter Case		Frequent	Extended	Infrequent	Frequent	Extended	Infrequent
MA Limit 2025 [1]		**7,380,000**	**7,380,000**	**7,380,000**	**7,380,000**	**7,380,000**	**7,380,000**
Central Cases							
MA CO_2 Emissions (metric tons)	CMR	8,824,865	8,037,318	7,691,581	8,623,248	7,835,701	7,489,964
	ESI	8,748,793	7,976,487	7,681,679	8,547,176	7,774,871	7,480,062
	Change	(76,072)	(60,831)	(9,902)	(76,072)	(60,831)	(9,902)
$5 MA CO_2 Adder							
MA CO_2 Emissions (metric tons)	CMR	8,515,251	7,731,520	7,385,709	8,289,895	7,506,164	7,160,353
	ESI	8,432,947	7,673,953	7,375,569	8,207,592	7,448,598	7,150,213
	Change	(82,304)	(57,567)	(10,140)	(82,304)	(57,567)	(10,140)

3. Oil Starting Inventory, Oil Holding Costs, and LNG Contracting

a) Oil Starting Storage

Resources that use oil for their primary or secondary fuel have additional characteristics related to fuel storage, consumption, and replenishment rates. These refueling characteristic assumptions are based on periodic oil resource survey data from August 2014 through April 30, 2019, received from ISO-NE. Under CMR, historic inventory levels are used.

This section describes our assumptions of each resource's starting storage under CMR and ESI.

i) Initial Inventory under Current Market Rules

Each resource's projected starting storage under current market rules is based on the 2018-2019 average inventory as of December 1st.

81 In principle, actual emissions can be above the statutory cap through the use of banking provisions in the Massachusetts system. However, the consequences of banking for compliance in a given future year are complex, due to certain dynamic adjustments made to total annual allowance allocations when allowance banking occurs in prior years. Thus, determining precise thresholds for compliance in future years is difficult.

ii) Initial Inventory under ESI

Each resource's average December inventory over the period 2014 to 2016 is used as a starting point for determining the quantity of fuel assumed under ESI. From this starting point, adjustments are made to reflect multiple factors associated with the benefits of incremental storage, relative to CMR levels:

1. For a subset of resources with at least seven days of storage, initial inventory is set to their CMR (December 2018) initial inventory level. Analysis found that further increasing initial inventories for these resources beyond 7-days of fuel provided little economic value, potentially imposing holding costs in excess of additional revenues.
2. For resources with smaller tank sizes (no more than three days of storage and refueled by truck) and inventories at low levels over the period 2014 to 2016, initial inventories are set, at a minimum, to 70 percent of their maximum storage. These resources accrue sufficient energy option revenues and FER payments to compensate their incremental oil holding costs.
3. The most-efficient (low heat rate) resources are assumed to hold larger initial inventories, set at 5% or 10% above average December inventories for 2014 to 2016 depending on the level of efficiency.
4. The most-inefficient (high heat rate) resources are assumed to hold smaller initial inventories, set at the mid-point between the average December 2014-16 inventories and the average December 2018 inventory (i.e., the level assumed under CMR).

Resources that refuel their oil inventory via pipeline are assumed to refuel oil as often as is required to supply energy under both CMR and ESI.

b) Oil Holding Costs

Storing oil imposes an economic cost, referred to as a "holding cost." If a resource procures stored fuel oil, there is risk that this fuel is not consumed during the winter season, and the resource is still holding the fuel at the end of the winter. We measure the cost associated with holding quantities of oil at the end of a winter season. We model holding costs as the combination of three costs faced by any resource that purchases oil: fuel carrying cost, price risk, and liquidity risk.

- **Carrying Cost**: carrying cost reflects the opportunity cost of purchasing oil and storing it for a period of time in a tank rather than using the capital in another way. The risk free component of a resource's weighted average cost of capital represents this opportunity cost of funds.
- **Liquidity Risk**: once purchased, fuel-oil can be difficult to re-sell. Being left with oil in the tank at the end of a winter season may therefore tie up valuable assets for the resource until the next winter season. This liquidity risk can be represented as a risk premium on top of the risk-free opportunity cost of capital, or simply the difference between a resource's weighted average cost of capital and the risk-free rate (often represented by T-bills). Thus, taken together, the carrying cost and liquidity risk can be represented by a resource's weighted average cost of capital.
- **Price Risk**: price risk refers to the risk a resource faces of the price of oil falling below the original purchase price before the end of the storage period (e.g. the end of the winter season). If the price of oil falls below its original purchase price, the resource will be left with a depreciated asset. The price

of a "put option"—a financial instrument that offers the purchaser of the option the opportunity to sell the product (in this case oil) at a pre-determined price—reflects the value of this price risk.

The combination of carrying cost, liquidity risk, and price risk represent an upper bound on the holding costs a resource may incur. We estimate holding costs in dollars per megawatt-hour ($ per MWh) for each generating unit based on the amount of fuel it has remaining at the end of the winter model run. Specifically, for each unit, we calculate the following relationship:

Holding cost ($/MWh) = holding cost ($/BBL) ÷ fuel energy content (MMBtu/BBL) × unit heat rate (Btu/kWh/1000)

Where the components are defined as:

- ***holding cost ($/BBL)*****:** the combination of carrying cost, liquidity risk, and price risk for units combusting RFO and DFO. Drawing from past work, we estimate carrying cost and liquidity risk as the weighted average cost of capital of the price of RFO or DFO in $/BBL.[82] To represent price risk, we draw from past work that estimated a fuel specific premium payment on a put option. We illustrate our assumptions in the table below:

Table 60. Fuel Holding Costs ($/BBL)

	Fuel Price [A]	WACC [B]	Put Option [C]	Holding Cost [D] = [A]×[B] + [C]
RFO	$88.30 / BBL	8%	$6.14	$13.20 / BBL
DFO	$89.54 / BBL	8%	$8.46	$15.62 / BBL

- ***fuel energy content (MMBtu/BBL)*****:** RFO and DFO contain different energy contents per barrel of fuel. Specifically, RFO contains 6.287 MMBtu per BBL and DFO contains 5.817 MMBtu per BBL.[83]
- ***unit heat rate (Btu/kWh)*****:** We derive unit specific heat rates from SNL Financial. SNL reports values in Btu per kWh. To convert to MMBtu per MWh, we divide by 1,000.[84]

c) Natural Gas Modeling

In winter months under CMR and in non-winter months under both CMR and ESI, we assume no forward LNG contracting. However, in the winter months under ESI, we assume that market participants would enter into forward contracts with LNG terminals that provide supplies of natural gas. The total capacity of natural gas available for forward contracting was determined through an analysis of various demands on LNG terminal

82 Hibbard, Paul and Todd Schatzki, "Further Explanation on Rate Calculations," May 28, 2014. https://www.iso-ne.com/static-assets/documents/committees/comm_wkgrps/mrkts_comm/mrkts/mtrls/2014/jun32014/a02a_analysis_group_memo_05_28_14.pdf

83 "Energy Units and Calculators, Explained," U.S. Energy Information Administration, https://www.eia.gov/energyexplained/index.php?page=about_energy_units.

84 (Btu / kWh) × (1000 kWh / 1 MWh) × (1 MMBtu / 1,000,000 Btu) = MMBtu / 1,000 MWh.

capability during the future modelled year, 2025/26. This analysis considers the capacity available from the LNG terminals, as the terminals would not be expected to sign contracts for supplies that exceed the capacity they can deliver on each day. This analysis is shown in **Table 61**.

First, we estimate the amount of LNG that would be needed to meet LDC demand on a "design day". These LNG supplies are needed by LDCs to ensure they can meet peak demand on a "design day," the hypothetical day in which the LDCs are expected to put the greatest demand on the gas system. LDC design day needs are estimated to be 0.71 Bcf per day.

Second, we determined available natural gas supply from the LNG terminals. With the assumed retirement of DOMAC, supplies are assumed to be provided by Canaport, as limited by pipeline capability. Potential natural gas supply capacity from the LNG terminals is estimated to be 0.833 Bcf per day.

Third, deliverable natural gas capacity for the electricity sector was calculated as the difference between potential capacity from the LNG terminals and LDC design day demand. The amount is 0.12 Bcf per day. Thus we assume that forward contracts for this amount of fuel would be available to the electric power sector.

Table 61. Quantity Available for LNG Forward Contracting[85]

			Source
LDC Design Day Temperature (HDD)	[A]	75	Assumption
Pipeline Import Capacity (Bcf/day)	[B]	3.59	FCA 14 presentation
LDC Demand on Design Day (Bcf/day, ISO Model)	[C]	5.76	ISO NE model
Satellite LNG Injection Quantity on Design Day (Bcf/day, ISO Model)	[D]	1.46	ISO NE model, capped at 1.456 Bcf/day
LDC Design Day Demand to be met by LNG (Bcf/day)	[E]=[C]-[B]-[D]	**0.71**	
Assuming LDCs contract LDC Design Day Demand as firm capacity with LNG terminals…			
Canaport LNG Terminal Capacity (Bcf/day)	[F]	1.20	OFSA
M&N Pipeline Capacity (Bcf/day)	[G]	0.833	OFSA
Canaport Deliverable Capacity (Bcf/day)	[H]= Min([F],[G])	0.833	OFSA
Total LNG Capacity without DOMAC (Bcf/day)	[I]=[H]	**0.833**	Calculation
Total LNG Capacity Available for LNG Forward Contracting without DOMAC (Bcf/day)	[J]=[I]-[E]	**0.12**	
Total LNG Capacity Available for LNG Forward Contracting without DOMAC (MMBtu/hr)	[K] = [J] converted	**5,313**	
Total Gas-only Capacity assumed with LNG forward contracts (SCC MW)	[L]	**616**	Based on most efficient gas-only units
Percentage of LNG reserved for Design Day Demand available for electrical generators		**100%**	

85 Sources are: [1] Norman Sproehnle, "Reliability Reviews for Fuel Security: Model Inputs, Results, and Criteria for Unit Retention in the Forward Capacity Market (FCM)," July 31, 2018, "a2_1_iso_presentation_reliability_reviews_for_fuel_security.pptx"; [2] ISO-

The forward LNG contract was assigned to the more efficient combined cycle gas-only resources. We assume that the forward contract would have 10 call options over the 90-day winter period. The modeled contract has a reservation of $13.19 per MMBtu, and a strike price of $10 per MMBtu.[86] This means that resources must pay $13.19 per MMBtu prior to the winter to secure the contract, then will be able to purchase gas at the strike price of $10 per MMBtu when exercising a call.

d) Incentives for Investment in Incremental Fuel Oil, Scenario Results

Section IV.A analyzes the incentives for investment in incremental fuel oil. Our analyses include **Table 11** to **Table 13**, which compare the new revenues created by ESI to incent fuel oil use, through FER payments and DA energy option procurement, against incremental fuel oil holding costs. **Table 62** to **Table 64** provide the same comparison for several alternate ESI designs, including the RER Plus, Strike Plus $10, and No RER scenarios, for the Frequent, Extended and Infrequent Cases, respectively. These tables provide the *change* in net revenues (new ESI revenues net of holding cost) for holding incremental fuel oil under each alternate ESI design as compared to CMR.

Directionally, the change in net revenue from each alternate ESI design, as compared to the ISO-NE proposal, reflects the change in scope of the services procured relative to the ISO-NE proposal.[87] For example, a larger RER quantity ("RER Plus") leads to a larger increase in net revenues from holding incremental fuel oil, while eliminating the RER ("No RER") reduces the net revenues from holding incremental fuel oil relative to the ESI proposal.

As the results in **Table 62** to **Table 64** demonstrate, proposals to reduce the ESI services procured, such as the elimination of RER, would tend to reduce the aggregate incentive to procure incremental fuel oil relative to the ISO-NE proposal. More importantly, this reduction in incentive would also reduce incentives *on the margin*, as the elimination of RER tends to reduce FER and GCR prices, especially during periods of system stress. This result was illustrated in **Figure 20** and **Figure 21**. These lower prices would reduce the revenues earned from selling DA energy or ancillary services during periods of system stress, and may therefore reduce the likelihood that oil units (or other resources) procure fuel (or take other actions) necessary to sell these products and ensure that they are available to provide energy in RT. Reducing such incentives would therefore adversely impact the design's ability to improve the region's energy security by incenting greater fuel procurement.

NE, LDC Gas Demand model, "2018_ICF_LDC_gas_demand.xlsx" [3] ISO-NE, "Operation Fuel-Security Analysis," January 17, 2018. [4] Discussion with ISO-NE, July 10, 2019.

[86] Analysis performed in the context of analysis performed for the interim inventories energy program. *See* Testimony of Todd Schatzki, Federal Energy Regulatory Commission, Docket No. ER19-1428-000.

[87] We caution the reader from drawing precise quantitative conclusions about the magnitudes of these incentives under the alternatives as they compare to the ISO's proposal. The values presented in **Table 62** to **Table 64** for RER Plus and Strike Price plus $10 reflect the same incremental fuel inventory assumptions as in the Central Case, while the No RER value assumes one-half of the incremental fuel inventory as was assumed in the Central Case. In each case, these assumptions are not precisely calibrated to reflect the differences in incentives under each alternative design relative to the ISO's proposal.

Table 62. New ESI Revenues and Change in Holding Costs, Winter Frequent Scenarios

Technology Type	Number of Units	Change in Holding Costs ($ / MW)	ESI FER Payments ($ / MW)	ESI DA Energy Option Revenue ($ / MW)	Change in Net Revenue ($ / MW)
Central Case					
Dual Fuel, Combined Cycle	17	-$14	$5,452	$139	$5,577
Dual Fuel, CT	14	-$118	$5,875	$2,172	$7,929
Oil Only, CT	70	-$134	$1,784	$5,735	$7,385
Oil Only, Steam	13	-$1,257	$6,207	$583	$5,532
RER Plus					
Dual Fuel, Combined Cycle	17	-$6	$6,616	$221	$6,831
Dual Fuel, CT	14	-$110	$7,129	$2,875	$9,894
Oil Only, CT	70	-$134	$2,141	$7,632	$9,639
Oil Only, Steam	13	-$1,256	$7,595	$1,055	$7,394
Strike Plus $10					
Dual Fuel, Combined Cycle	17	-$14	$5,427	$124	$5,537
Dual Fuel, CT	14	-$118	$5,955	$1,940	$7,777
Oil Only, CT	70	-$134	$1,827	$5,219	$6,911
Oil Only, Steam	13	-$1,257	$6,315	$561	$5,619
No RER					
Dual Fuel, Combined Cycle	17	-$1	$3,564	$47	$3,610
Dual Fuel, CT	14	-$71	$2,946	$1,317	$4,192
Oil Only, CT	70	-$91	$851	$1,844	$2,604
Oil Only, Steam	13	-$1,406	$3,179	$111	$1,884

Note: Combustion Turbine (CT) category includes CT’s and internal combustion units.

Table 63. New ESI Revenues and Change in Holding Costs, Winter Extended Scenarios

Technology Type	Number of Units	Change in Holding Costs ($ / MW)	ESI FER Payments ($ / MW)	ESI DA Energy Option Revenue ($ / MW)	Change in Net Revenue ($ / MW)
Central Case					
Dual Fuel, Combined Cycle	17	-$112	$2,113	$61	$2,063
Dual Fuel, CT	14	-$124	$1,760	$1,199	$2,835
Oil Only, CT	70	-$88	$654	$2,032	$2,598
Oil Only, Steam	13	-$1,291	$2,646	$98	$1,453
RER Plus					
Dual Fuel, Combined Cycle	17	-$112	$2,628	$110	$2,627
Dual Fuel, CT	14	-$124	$2,410	$1,641	$3,927
Oil Only, CT	70	-$88	$891	$3,296	$4,099
Oil Only, Steam	13	-$1,288	$3,597	$230	$2,539
Strike Plus $10					
Dual Fuel, Combined Cycle	17	-$112	$2,096	$55	$2,039
Dual Fuel, CT	14	-$124	$1,685	$1,069	$2,630
Oil Only, CT	70	-$88	$630	$1,857	$2,399
Oil Only, Steam	13	-$1,291	$2,552	$102	$1,364
No RER					
Dual Fuel, Combined Cycle	17	-$6	$1,207	$23	$1,223
Dual Fuel, CT	14	-$116	$868	$416	$1,167
Oil Only, CT	70	-$80	$267	$339	$527
Oil Only, Steam	13	-$819	$1,316	$13	$509

Note: Combustion Turbine (CT) category includes CT's and internal combustion units.

Table 64. New ESI Revenues and Change in Holding Costs, Winter Infrequent Scenarios

Technology Type	Number of Units	Change in Holding Costs ($ / MW)	ESI FER Payments ($ / MW)	ESI DA Energy Option Revenue ($ / MW)	Change in Net Revenue ($ / MW)
Central Case					
Dual Fuel, Combined Cycle	17	-$254	$785	$12	$543
Dual Fuel, CT	14	-$435	$150	$444	$159
Oil Only, CT	70	-$84	$7	$720	$643
Oil Only, Steam	13	-$1,315	$94	$3	-$1,218
RER Plus					
Dual Fuel, Combined Cycle	17	-$254	$961	$38	$745
Dual Fuel, CT	14	-$435	$182	$560	$307
Oil Only, CT	70	-$84	$5	$1,270	$1,191
Oil Only, Steam	13	-$1,315	$101	$21	-$1,194
Strike Plus $10					
Dual Fuel, Combined Cycle	17	-$254	$541	$10	$296
Dual Fuel, CT	14	-$435	$106	$394	$65
Oil Only, CT	70	-$84	$5	$659	$581
Oil Only, Steam	13	-$1,315	$69	$3	-$1,243
No RER					
Dual Fuel, Combined Cycle	17	-$193	$662	$3	$472
Dual Fuel, CT	14	-$298	$120	$221	$43
Oil Only, CT	70	-$66	$3	$89	$27
Oil Only, Steam	13	-$709	$81	$0	-$628

Note: Combustion Turbine (CT) category includes CT's and internal combustion units.

C. Day-Ahead Energy Options Offers

ESI requires the procurement of DA energy options from suppliers in the market. Under ESI, market participants would submit offers reflecting their willingness to accept the obligation to settle ("closeout") at the option's pay out terms. In principle, this valuation reflects many factors, such as the expected payout, the risk associated with the option, and the resulting financial risk faced by market participants, given a potential correlation between option settlement and other revenue streams.

To estimate offer prices for DA energy options, we assume that suppliers' willingness to accept the settlement obligation reflects expected closeout costs plus a premium to capture the financial risk associated with the uncertain closeout costs. Thus, valuations will reflect each market participant's expectations regarding likely costs and associated risks, potentially modified by opportunities to hedge such risks through other market products.[88] Further, the ESI design assumes that all market participants submit offers for DA energy options that reflect their underlying valuation, with the resulting market-clearing price reflecting the marginal offer given the quantity administratively procured. The resulting price may differ from the price that emerges from financial markets, where equilibrium prices reflect bi-lateral transactions between those willing to accept and willing to pay for the option, as ISO-NE procures the options on behalf of consumers. The finance literature does not provide unique methodologies to estimate option offer prices under these circumstances.

The energy option offer includes two components: the expected closeout costs and a risk premium. First, we describe the approach taken to estimating the expected closeout costs and then describe the approach taken to estimating the risk premium.

1. Expected Closeout Costs

The estimates for the expected closeout costs are based on the difference between the real-time LMP (RT LMP), and the "strike price" (K) in each hour. Resources owe a payment of $(RT\ LMP - K)$ to closeout the option, if the option is "in the money", or when $(RT\ LMP - K) > 0$. Otherwise the payout is zero. Thus, the key driver of the bidding for the ESI products is the volatility of the real-time settlement, or in other words, $max\{(RT\ LMP - K), 0\}$.

For each hour when estimating offer prices, the **strike price, *K*,** is set to be equal to the historic **DA LMP** in that hour.

We compute the expected closeout costs through a multi-step process.

1. We use historical data provided by ISO-NE on LMPs between June 2012 and May 2019 to compute the historical time series of **RT LMP** minus **K**.

[88] Cochrane and Saa-Requejo, 1999, consider approaches to derivative valuation that reflect "good deals" given opportunities to partially hedge a derivatives risk.

2. We estimate fitted values for the difference in RT LMP and strike price $(RT\ LMP - K)$ for each hour. This fitted value provides a single, point estimate of $(RT\ LMP - K)$. The fitted value is estimated using the following linear model, estimated over our sample:

$$(RT\ LMP - K) = \beta_1(HDD) + \beta_2(Hour\ of\ Day) + \beta_3(Day\ of\ Week) + \beta_4(Month\ of\ Winter) + \beta_4(Winter) + \varepsilon$$

3. We calculate model residuals ε from our estimated model as the difference between the actual $(RT\ LMP - K)$ and the fitted $(RT\ LMP - K)$.
4. Using a Monte Carlo method, we simulate a distribution for $(RT\ LMP - K)$. To create this simulated distribution for each hour, we take the fitted value and randomly draw one residual from the sample of model residuals, ε. We replicate this step 1,000 times (with replacement) to create a distribution of $(RT\ LMP - K)$ with 1,000 values.
5. Having created the distribution of $(RT\ LMP - K)$ with 1,000 simulated values for each hour, we then calculate the closeout costs in each simulated hour in the distribution – i.e.,$Y_i = max(LMP - K + \varepsilon_i, o)$. Having calculated the closeout cost for each hour in the distribution, we then estimate the mean of all simulated Y_i's in each hour to obtain the expected closeout costs in that hour, $\overline{Y_t}$.

Steps 1 to 2 provide a point estimate for $(RT\ LMP - K)$, while steps 3 to 5 account for the impact of the asymmetry in the closeout costs of the DA energy option on the expected closeout costs. That is, because the closeout cost is the maximum of $(RT\ LMP - K)$ and zero (i.e., $max(LMP^{RT} - K, 0)$), there is a positive closeout cost only when the RT LMP exceeds the strike price and no closeout cost when the RT LMP falls below (or is equal to) the strike price.

To illustrate this asymmetry, consider the following illustrative example shown in **Table 65**. Assume that the strike price is $40 per MWh and the model estimates that $(RT\ LMP - K)$ is $5 per MWh, implying a RT LMP of $45 per MWh. Further, assume there is a 50% probability that the RT LMP is $10 per MWh lower than this expected RT value of $45 per MWh, and a 50% probability that the RT LMP is $10 per MWh higher. This uncertainty does not change the expected value – the average of $(RT\ LMP - K)$ is still $5 per MWh even if there is a 50% probability the price is –$5 per MWh and 50% probability the price is $15 per MWh. However, this uncertainty has an asymmetric effect on the option closeout costs, as there is a 50% probability the closeout cost is $15 per MWh and a 50% probability the closeout cost is $0 per MWh, such that the average closeout cost is $7.50 per MWh, not $5 per MWh.

Table 65. Illustrative Example of Asymmetric Effect of Uncertainty on Option Closeout

	Case Probability	Fitted Value (RT LMP - K)	Realized (RT LMP - K)	Option Closeout Cost
Case 1	50%	$5.00	-$5.00	$0.00
Case 2	50%	$5.00	$15.00	$15.00
Expected Value			$5.00	$7.50

When sampling residuals from the estimated model, we restrict the sample to residuals from that historical year. The model is fit to winter months only (December, January, and February) when estimating offer prices for the winter month analyses. For the non-winter months, the same model is fit to each nine month period comprising the two non-winter seasons. Additionally, for the non-winter cases offers are modeled separately for each season (spring, summer, and fall), to account for seasonal differences.

2. Approach to Estimating a DA Risk Premium

The approach taken to estimating a risk premium builds off the observation that the same risk preferences underlying risk premiums for derivatives traded in electricity markets should underlie risk premiums for DA energy options.[89] Thus, while there is limited market information on energy options, electricity forwards (e.g., a DA energy) are commonly traded in electricity markets, including New England's energy markets.[90]

Our approach accounts for a number of reasonable features of the risk premiums:

1. The risk premium reflects the (magnitude of) financial risk taken on when awarded a DA energy option. Thus, all else equal, the size of the risk premium increases with the variability of LMPs. Moreover, the risk premium may increase disproportionately with the level of financial risk assumed, if market participants are disproportionately averse to large losses. Thus, there could be a non-linear (convex) relationship between the risk premium and metrics of financial risk (e.g., the variability in returns).
2. The risk premium is larger for a resource with no energy inventory, as it faces a riskier, unhedged financial position.
3. The risk premium varies the resource's marginal cost of supplying energy, as it bounds the potential loss to (*MC* – *K*), providing a partial hedge on the DA energy option settlement risk.
4. The risk premium could be negative for resources for which the DA energy option lowers financial risk (e.g., if the resource has low *MC* relative to *K*).
5. The risk premium will depend on operational and intertemporal factors that prevent physical energy inventory from perfectly hedging financial risks.

DA energy option risk premiums are estimated using the following equation for unit *j* at time *t*:

89 Because the DA energy options will not be a traded product, but cleared through a market with fixed demand, and because the DA energy options are real options that cannot be replicated through existing financial markets (i.e., they are not spanned), conventional derivative pricing models are not appropriate to determining market participant bids to supply the DA energy options (e.g., see Cochrane, John and Jesus Saa-Requejo, 1999, "Beyond Arbitrage: Good-Deal Asset Price Bounds in Incomplete Markets.")

90 Prior research shows that risk premiums for day-ahead positions vary with multiple factors, particularly expected RT price variability and skewness. Observed risk premiums reflect an equilibrium outcome in which both buyers and sellers may desire to mitigate the risk of real-time energy market sales. Jacobs, Li and Pirrong (2017), for example, find that the equilibrium risk premium, reflecting both seller and buyer premiums, is 1% to 2%, with larger values in more volatile winter periods, while Bunn and Chen (2013) find Great Britain winter premiums are 7.2% for on-peak and 4.8% for off-peak, while summer premiums are –1.3% for on-peak and –1.0% for off-peak. We are not aware of empirical research that has performed such empirical analysis for electricity options. Bessimbinder, Hendrik and Michael Lemmon, "Equilibrium Pricing and Optimal Hedging in Electricity Forward Markets"; Bunn, Derek and Dipeng Chen, 2013, "The forward premium in electricity futures," Journal of Empirical Finance, 23: 173-186.; Cochrane, John and Jesus Saa-Requejo, 1999; and Jacobs, Kris, Yu Li, and Craig Pirrong, 2017, "Supply, Demand, and Risk Premiums in Electricity Markets."

$$r_{o,j,t} = r_f * \frac{R_t}{C_t} * \left(\frac{\sigma_{o,j}}{\sigma_f}\right)^{\gamma} * p_j$$

Where:

- $r_{o,t}$ is the option risk premium for hour *t*
- r_f is the average day-ahead unhedged forward risk premium for hour *t*, assumed to be 0.015 (i.e., a 1.5% risk premium)
- R_t is the (expected) real-time price, estimated as the day-ahead price for hour *t*
- C_t is the (expected) call option price, estimated as the expected close out cost for hour *t*
- σ_o, σ_f is the standard deviation of margins earned for the option for either option or forward contract, measured for peak and off-peak hours[91]
- γ allows for a non-linear relationship between RT settlement risk (variability) and risk premium, and is assumed to be 1 (i.e., no non-linear relationship is assumed, at present)
- p is a unit-specific adjustment to account for intertemporal constraints to the delivery of energy at *MC*, such as lost opportunities (revenues) due to start-up lead-time and operational risk

This formula starts with an estimate of the average day-ahead forward risk premium (in percentage terms), reflecting a range of market conditions. This risk premium is then adjusted for several factors:

- First, risk premiums are adjusted for the size of the option price relative to the forward price $\left(\frac{R_t}{C_t}\right)$. Within the finance literature, this is referred to as the assets delta. This adjustment accounts for the fact that an investor will require the same compensation to bear the same risk, irrespective of the instrument's price. Adjusting the risk premium for the relative prices ensures that this is the case.
- Second, the risk premium is adjusted to account for relative differences in the size of the risk, as measured by the standard deviation of the (negative) returns $\left(\frac{\sigma_{o,j}}{\sigma_f}\right)^{\gamma}$.
- Third, the risk premium is adjusted for operational risks, including intertemporal constraints. The estimated risk (variability) of returns to the DA energy option assumes that the resource always delivers energy whenever LMP^{RT} > MC. However, in practice, within the real-time market, multiple factors may limit the extent to which a resource can supply energy. The adjustment factor, *p*, accounts for these factors.

Under this approach: several of the parameters, r_f, *p*, σ_f and γ, are constant across offers; two parameters, R_t and C_t, vary by hour; and one parameter, σ_o, varies across resources. Currently, the standard deviation of the option, σ_o, is calculated for each resource in each hour as a function of $\Delta = MC - K$ for peak and off-peak periods. Estimates of σ_o are based on the following function for peak and off-peak hours ($h = \{peak, offpeak\}$):

---

[91] Assuming that σ_f reflects both negative and positive outcomes from a risk perspective, we focus on only the negative outcomes (i.e., outcomes that lead to a negative settlement versus the RT price) when measuring the risk premium. To do so, we assume the distribution of outcomes is symmetric, and simply divide σ_f by 2 under the assumption that one-half the variability (that associated with positive settlement) requires no risk premium.

$$\sigma_o = \beta_{0,h} + \beta_{1,h}\sqrt{\Delta}$$

Based on a linear regression where a separate linear equation is estimated for each LMP quartile for on- and off-peak hours. Estimates of $\beta_{0,i,p}$ and $\beta_{i,p}$ are estimated using historical data on market outcomes in New England's electricity markets.

With this risk premium adjustment, the bid will be the expected closeout cost adjusted for the risk premium – that is:

$$offer_{i,t} = CVC + PVC = E[max(0, RT\ LMP - K)] * (1 + r_{o,i,t}) = E[\cdot] * \left(1 + r_{f,t} * \frac{R_t}{C_t} * \frac{\sigma_o}{\sigma_f} * p_i\right)$$

$$= E[\cdot] * (1 + k_t \sigma_{o,i,t} * p_i) = E[\cdot] * \left(1 + (k_t\beta_0 + k_t\beta_1\sqrt{\Delta^*_{i,t}}) * p_i\right)$$

Where

- $k_t = r_{f,t} * \frac{R_t}{C_t\sigma_f}$
- $E[\cdot] = E[max(0, RT\ LMP - K)]$ is calculated through fitted regression and Monte Carlo analysis, as described above
- $\Delta^*_{i,t} = m_i MC_i - K$, where m_i is an additional adjustment parameter to account for unit-specific cost factors such as start-up costs and fuel cost risk

Table 66. Operational and Intertemporal Factors Accounted for in Risk Premium[92]

	Operational / Intertemporal Factors (p)			***Cost Factors (m)***		
	Performance Risk	Lead Time	Total	Fuel Cost Risk	Start-up Cost	Total
	[A]	[B]	[A]*[B]*[C]	D	E	[D]*[E]
Combustion Turbines						
Gas-only	1.05	1	1.05	1.5	1.45	2.18
Oil-only	1.05	1	1.05	1	1.45	1.45
Dual Fuel	1.05	1	1.05	1	1.45	1.45
Combined Cycle						
Gas-only	1.1	1.25	1.38	1.5	1.25	1.88
Oil-only	1.1	1.25	1.38	1	1.25	1.25
Dual Fuel	1.1	1.25	1.38	1	1.25	1.25
LNG Contract	1.1	1.25	1.38	1	1.25	1.25
Steam						
Oil-only	1.3	2	2.60	1	1.25	1.25
Dual Fuel	1.3	2	2.60	1	1.25	1.25

92 To account for the reduced incidence of high natural gas price days in the non-winter months, gas-only Combustion Turbine and Combined Cycle units are modeled with a reduced "Fuel Cost Risk" multiplier of 1 in the non-winter months.

D. Posted Output Data

Along with this report, hourly results from the integrated production cost model for the winter Central Cases and the non-winter Cases have also been publically posted.[93] These data include market-clearing prices and quantities for DA and RT products (e.g. DA and RT energy, RT operating reserves, as well as DA AS products when applicable) in every hour of the modeled period. In addition, information on the day-ahead forecasted load is included for all cases, while various metrics related to the settlement of DA financial option products – such as the hourly real-time closeout price, and the hourly FER/EIR price – are included for ESI cases only.

For a given hour, these data present outcomes in the real-time market alongside that hour's corresponding day-ahead market outcomes. For example, hourly results listed for 12 PM on January 2nd, 2026 correspond to the real-time market solved in that hour and the day-ahead market solved on the prior day, for delivery the next day (i.e., the day-ahead market solved for delivery at 12 PM on January 2nd).

The quantities for DA and RT products reflect the total MW commitment across all resources in the New England region in a given hour. The clearing prices listed in these hourly results are the shadow price for the relevant product constraint, optimized over the entire New England fleet. For more information on how clearing prices for DA and RT products are set by the production cost model, please consult **Section III.3** of this report.

For ESI cases, shortages for GCR, and RER energy option products occur when the total hourly commitment does not satisfy the hourly requirements (2,400 MW and 1,200 MW, respectively). EIR shortages occur when the sum of EIR and DA generation together in a given hour is less than the forecasted load quantity.

93 This data is available at https://www.iso-ne.com/static-assets/documents/2020/02/a4_e_preliminary_esi_impact_analysis_hourly_model_outputs.xlsx.

Attachment D-1

ISO Marked Tariff

I.2 Rules of Construction; Definitions

I.2.1. Rules of Construction:

In this Tariff, unless otherwise provided herein:

(a) words denoting the singular include the plural and vice versa;

(b) words denoting a gender include all genders;

(c) references to a particular part, clause, section, paragraph, article, exhibit, schedule, appendix or other attachment shall be a reference to a part, clause, section, paragraph, or article of, or an exhibit, schedule, appendix or other attachment to, this Tariff;

(d) the exhibits, schedules and appendices attached hereto are incorporated herein by reference and shall be construed with an as an integral part of this Tariff to the same extent as if they were set forth verbatim herein;

(e) a reference to any statute, regulation, proclamation, ordinance or law includes all statutes, regulations, proclamations, amendments, ordinances or laws varying, consolidating or replacing the same from time to time, and a reference to a statute includes all regulations, policies, protocols, codes, proclamations and ordinances issued or otherwise applicable under that statute unless, in any such case, otherwise expressly provided in any such statute or in this Tariff;

(f) a reference to a particular section, paragraph or other part of a particular statute shall be deemed to be a reference to any other section, paragraph or other part substituted therefor from time to time;

(g) a definition of or reference to any document, instrument or agreement includes any amendment or supplement to, or restatement, replacement, modification or novation of, any such document, instrument or agreement unless otherwise specified in such definition or in the context in which such reference is used;

(h) a reference to any person (as hereinafter defined) includes such person's successors and permitted assigns in that designated capacity;

(i) any reference to "days" shall mean calendar days unless "Business Days" (as hereinafter defined) are expressly specified;

(j) if the date as of which any right, option or election is exercisable, or the date upon which any amount is due and payable, is stated to be on a date or day that is not a Business Day, such right, option or election may be exercised, and such amount shall be deemed due and payable, on the next succeeding Business Day with the same effect as if the same was exercised or made on such date or day (without, in the case of any such payment, the payment or accrual of any interest or

other late payment or charge, provided such payment is made on such next succeeding Business Day);

(k) words such as "hereunder," "hereto," "hereof" and "herein" and other words of similar import shall, unless the context requires otherwise, refer to this Tariff as a whole and not to any particular article, section, subsection, paragraph or clause hereof; and a reference to "include" or "including" means including without limiting the generality of any description preceding such term, and for purposes hereof the rule of *ejusdem generis* shall not be applicable to limit a general statement, followed by or referable to an enumeration of specific matters, to matters similar to those specifically mentioned.

I.2.2. Definitions:

In this Tariff, the terms listed in this section shall be defined as described below:

Active Demand Capacity Resource is one or more Demand Response Resources located within the same Dispatch Zone, that is registered with the ISO, assigned a unique resource identification number by the ISO, and participates in the Forward Capacity Market to fulfill a Market Participant's Capacity Supply Obligation pursuant to Section III.13 of Market Rule 1.

Actual Capacity Provided is the measure of capacity provided during a Capacity Scarcity Condition, as described in Section III.13.7.2.2 of Market Rule 1.

Actual Load is the consumption at the Retail Delivery Point for the hour.

Additional Resource Blackstart O&M Payment is defined and calculated as specified in Section 5.1.2 of Schedule 16 to the OATT.

Additional Resource Specified-Term Blackstart Capital Payment is defined and calculated as specified in Section 5.1.2 of Schedule 16 to the OATT.

Additional Resource Standard Blackstart Capital Payment is defined and calculated as specified in Section 5.1.2 of Schedule 16 to the OATT.

Administrative Costs are those costs incurred in connection with the review of Applications for transmission service and the carrying out of System Impact Studies and Facilities Studies.

Administrative Export De-List Bid is a bid that may be submitted in a Forward Capacity Auction by certain Existing Generating Capacity Resources subject to a multi-year contract to sell capacity outside of the New England Control Area during the associated Capacity Commitment Period, as described in Section III.13.1.2.3.1.4 of Market Rule 1.

Administrative Sanctions are defined in Section III.B.4.1.2 of Appendix B of Market Rule 1.

ADR Neutrals are one or more firms or individuals identified by the ISO with the advice and consent of the Participants Committee that are prepared to act as neutrals in ADR proceedings under Appendix D to Market Rule 1.

Advance is defined in Section IV.A.3.2 of the Tariff.

Affected Party, for purposes of the ISO New England Billing Policy, is defined in Section 6.3.5 of the ISO New England Billing Policy.

Affiliate is any person or entity that controls, is controlled by, or is under common control by another person or entity. For purposes of this definition, "control" means the possession, directly or indirectly, of the authority to direct the management or policies of an entity. A voting interest of ten percent or more shall create a rebuttable presumption of control.

AGC is automatic generation control.

AGC SetPoint is the desired output signal for a Resource providing Regulation that is produced by the AGC system as frequently as every four seconds.

AGC SetPoint Deadband is a deadband expressed in megawatts that is applied to changing values of the AGC SetPoint for generating units.

Allocated Assessment is a Covered Entity's right to seek and obtain payment and recovery of its share in any shortfall payments under Section 3.3 or Section 3.4 of the ISO New England Billing Policy.

Alternative Dispute Resolution (ADR) is the procedure set forth in Appendix D to Market Rule 1.

Alternative Technology Regulation Resource (ATRR) is one or more facilities capable of providing Regulation that have been registered in accordance with the Asset Registration Process. An Alternative Technology Regulation Resource is eligible to participate in the Regulation Market.

Ancillary Services are those services that are necessary to support the transmission of electric capacity and energy from resources to loads while maintaining reliable operation of the New England Transmission System in accordance with Good Utility Practice.

Announced Schedule 1 EA Amount, Announced Schedule 2 EA Amount, Announced Schedule 3 EA Amount are defined in Section IV.B.2.2 of the Tariff.

Annual Transmission Revenue Requirements are the annual revenue requirements of a PTO's PTF or of all PTOs' PTF for purposes of the OATT shall be the amount determined in accordance with Attachment F to the OATT.

Annual Reconfiguration Transaction is a bilateral transaction that may be used in accordance with Section III.13.5.4 of Market Rule 1 to specify a price when a Capacity Supply Obligation is transferred using supply offers and demand bids in Annual Reconfiguration Auctions.

Applicants, for the purposes of the ISO New England Financial Assurance Policy, are entities applying for Market Participant status or for transmission service from the ISO.

Application is a written request by an Eligible Customer for transmission service pursuant to the provisions of the OATT.

Asset is a Generator Asset, a Demand Response Asset, a component of an On-Peak Demand Resource or Seasonal Peak Demand Resource, a Load Asset (including an Asset Related Demand), an Alternative Technology Regulation Resource, or a Tie-Line Asset.

Asset Registration Process is the ISO business process for registering an Asset.

Asset Related Demand is a Load Asset that has been discretely modeled within the ISO's dispatch and settlement systems, settles at a Node, has been registered in accordance with the Asset Registration

Process, and is made up of either: (1) one or more individual end-use metered customers receiving service from the same point or points of electrical supply with an aggregate average hourly load of 1 MW or greater during the 12 months preceding its registration; (2) a Storage DARD with a consumption capability of at least 0.1 MW; or (3) one or more storage facilities that are not Electric Storage Facilities with an aggregate consumption capability of at least 1 MW.

Asset Related Demand Bid Block-Hours are Block-Hours assigned to the Lead Market Participant for each Asset Related Demand bid. Blocks of the bid in effect for each hour will be totaled to determine the daily quantity of Asset Related Demand Bid Block-Hours. In the case that a Resource has a Real-Time unit status of "unavailable" for an entire day, that day will not contribute to the quantity of Asset Related Demand Bid Block-Hours. However, if the Resource has at least one hour of the day with a unit status of "available," the entire day will contribute to the quantity of Asset Related Demand Bid Block-Hours.

Asset-Specific Going Forward Costs are the net costs of an asset that is part of an Existing Generating Capacity Resource, calculated for the asset in the same manner as the net costs of Existing Generating Capacity Resources as described in Section III.13.1.2.3.2.1.1.1 (for an asset with a Static De-List Bid or an Export Bid) or Section III.13.1.2.3.2.1.1.2 (for an asset with a Permanent De-List Bid or Retirement De-List Bid).

Assigned Meter Reader reports to the ISO the hourly and monthly MWh associated with the Asset. These MWh are used for settlement. The Assigned Meter Reader may designate an agent to help fulfill its Assigned Meter Reader responsibilities; however, the Assigned Meter Reader remains functionally responsible to the ISO.

Auction Revenue Right (ARR) is a right to receive FTR Auction Revenues in accordance with Appendix C of Market Rule 1.

Auction Revenue Right Allocation (ARR Allocation) is defined in Section 1 of Appendix C of Market Rule 1.

Auction Revenue Right Holder (ARR Holder) is an entity which is the record holder of an Auction Revenue Right (excluding an Incremental ARR) in the register maintained by the ISO.

Authorized Commission is defined in Section 3.3 of the ISO New England Information Policy.

Authorized Person is defined in Section 3.3 of the ISO New England Information Policy.

Automatic Response Rate is the response rate, in MW/Minute, at which a Market Participant is willing to have a Regulation Resource change its output or consumption while providing Regulation between the Regulation High Limit and Regulation Low Limit.

Available Energy is a value that reflects the MWhs of energy available from an Electric Storage Facility for economic dispatch.

Available Storage is a value that reflects the MWhs of unused storage available from an Electric Storage Facility for economic dispatch of consumption.

Average Hourly Load Reduction is either: (i) the sum of the On-Peak Demand Resource's electrical energy reduction during Demand Resource On-Peak Hours in the month divided by the number of Demand Resource On-Peak Hours in the month; or (ii) the sum of the Seasonal Peak Demand Resource's electrical energy reduction during Demand Resource Seasonal Peak Hours in the month divided by the number of Demand Resource Seasonal Peak Hours in the month. The On-Peak Demand Resource's or Seasonal Peak Demand Resource's electrical energy reduction and Average Hourly Load Reduction shall be determined consistent with the resource's Measurement and Verification Plan, which shall be reviewed by the ISO to ensure consistency with the measurement and verification requirements, as described in Section III.13.1.4.3 of Market Rule 1 and the ISO New England Manuals.

Average Hourly Output is either: (i) the sum of the On-Peak Demand Resource's electrical energy output during Demand Resource On-Peak Hours in the month divided by the number of Demand Resource On-Peak Hours in the month; or (ii) the sum of the Seasonal Peak Demand Resource's electrical energy output during Demand Resource Seasonal Peak Hours in the month divided by the number of Demand Resource Seasonal Peak Hours in the month. Electrical energy output and Average Hourly Output shall be determined consistent with the resource's Measurement and Verification Plan, which shall be reviewed by the ISO to ensure consistency with the measurement and verification requirements, as described in Section III.13.1.4.3 of Market Rule 1 and the ISO New England Manuals.

Average Monthly PER is calculated in accordance with Section III.13.7.1.2.2 of Market Rule 1.

Backstop Transmission Solution is a solution proposed: (i) to address a reliability or market efficiency need identified by the ISO in a Needs Assessment reported by the ISO pursuant to Section 4.1(i) of Attachment K to the ISO OATT, (ii) by the PTO or PTOs with an obligation under Schedule 3.09(a) of the TOA to address the identified need; and (iii) in circumstances in which the competitive solution process specified in Section 4.3 of Attachment K to the ISO OATT will be utilized.

Bankruptcy Code is the United States Bankruptcy Code.

Bankruptcy Event occurs when a Covered Entity files a voluntary or involuntary petition in bankruptcy or commences a proceeding under the United States Bankruptcy Code or any other applicable law concerning insolvency, reorganization or bankruptcy by or against such Covered Entity as debtor.

Bilateral Contract (BC) is any of the following types of contracts: Internal Bilateral for Load, Internal Bilateral for Market for Energy, and External Transactions.

Bilateral Contract Block-Hours are Block-Hours assigned to the seller and purchaser of an Internal Bilateral for Load, Internal Bilateral for Market for Energy and External Transactions; provided, however, that only those contracts which apply to the Real-Time Energy Market will accrue Block-Hours.

Binary Storage DARD is a DARD that participates in the New England Markets as part of a Binary Storage Facility, as described in Section III.1.10.6 of Market Rule 1.

Binary Storage Facility is a type of Electric Storage Facility, as described in Section III.1.10.6 of Market Rule 1.

Blackstart Capability Test is the test, required by ISO New England Operating Documents, of a resource's capability to provide Blackstart Service.

Blackstart Capital Payment is the annual compensation, as calculated pursuant to Section 5.1, or as referred to in Section 5.2, of Schedule 16 to the OATT, for a Designated Blackstart Resource's Blackstart Equipment capital costs associated with the provision of Blackstart Service (excluding the capital costs associated with compliance with NERC Critical Infrastructure Protection Reliability Standards as part of Blackstart Service).

Blackstart Equipment is any equipment that is solely necessary to enable the Designated Blackstart Resource to provide Blackstart Service and is not required to provide other products or services under the Tariff.

Blackstart O&M Payment is the annual Blackstart O&M compensation calculated under either Section 5.1 or 5.2 of Schedule 16 of the OATT, as applicable.

Blackstart Owner is the Market Participant who is authorized on behalf of the Generator Owner(s) to offer or operate the resource as a Designated Blackstart Resource and is authorized to commit the resource to provide Blackstart Service.

Blackstart Service is the Ancillary Service described in Section II.47 of the Tariff and Schedule 16 of the OATT.

Blackstart Service Commitment is the commitment by a Blackstart Owner for its resource to provide Blackstart Service and the acceptance of that commitment by the ISO, in the manner detailed in ISO New England Operating Procedure No. 11 – Designated Blackstart Resource Administration (OP 11), and which includes a commitment to provide Blackstart Service established under Operating Procedure 11 – Designated Blackstart Resource Administration (OP11).

Blackstart Service Minimum Criteria are the minimum criteria that a Blackstart Owner and its resource must meet in order to establish and maintain a resource as a Designated Blackstart Resource.

Blackstart Standard Rate Payment is the formulaic rate of monthly compensation, as calculated pursuant to Section 5 of Schedule 16 to the OATT, paid to a Blackstart Owner for the provision of Blackstart Service from a Designated Blackstart Resource.

Blackstart Station is comprised of (i) a single Designated Blackstart Resource or (ii) two or more Designated Blackstart Resources that share Blackstart Equipment.

Blackstart Station-specific Rate Payment is the Commission-approved compensation, as calculated pursuant to Section 5.2 of Schedule 16 to the OATT, paid to a Blackstart Owner on a monthly basis for the provision of Blackstart Service by Designated Blackstart Resources located at a specific Blackstart Station.

Blackstart Station-specific Rate Capital Payment is a component of the Blackstart Station-specific Rate Payment that reflects a Blackstart Station's capital Blackstart Equipment costs associated with the provision of Blackstart Service (excluding the capital costs associated with compliance with NERC Critical Infrastructure Protection Reliability Standards as part of Blackstart Service).

Block is defined as follows: (1) With respect to Bilateral Contracts, a Bilateral Contract administered by the ISO for an hour; (2) with respect to Supply Offers administered by the ISO, a quantity with a related price for Energy (Supply Offers for Energy may contain multiple sets of quantity and price pairs for each hour); (3) with respect to Demand Bids administered by the ISO, a quantity with a related price for Energy (Demand Bids for Energy may contain multiple sets of quantity and price pairs for each hour); (4) with respect to Increment Offers administered by the ISO, a quantity with a related price for Energy (Increment Offers for Energy may contain multiple sets of quantity and price pairs for each hour); (5) with respect to Decrement Bids administered by the ISO, a quantity with a related price for Energy (Decrement Bids for Energy may contain multiple sets of quantity and price pairs for each hour); (6) with respect to Asset Related Demand bids administered by the ISO, a quantity with a related price for Energy (Asset Related Demand bids may contain multiple sets of quantity and price pairs for each hour); and (7) with respect to Demand Reduction Offers administered by the ISO, a quantity of reduced demand with a related price (Demand Reduction Offers may contain multiple sets of quantity and price pairs for the day).

Block-Hours are the number of Blocks administered for a particular hour.

Budget and Finance Subcommittee is a subcommittee of the Participants Committee, the responsibilities of which are specified in Section 8.4 of the Participants Agreement.

Business Day is any day other than a Saturday or Sunday or ISO holidays as posted by the ISO on its website.

Cancelled Start NCPC Credit is an NCPC Credit calculated pursuant to Appendix F to Market Rule 1.

Capability Demonstration Year is the one year period from September 1 through August 31.

Capacity Acquiring Resource is a resource that is seeking to acquire a Capacity Supply Obligation through: (1) a Capacity Supply Obligation Bilateral, as described in Section III.13.5.1, or; (2) an annual or monthly reconfiguration auction, as described in Section III.13.4.

Capacity Balancing Ratio is a ratio used in calculating the Capacity Performance Payment in the Forward Capacity Market, as described in Section III.13.7.2.3 of Market Rule 1.

Capacity Base Payment is the portion of revenue received in the Forward Capacity Market as described in Section III.13.7.1 of Market Rule 1.

Capacity Capability Interconnection Standard has the meaning specified in Schedule 22, Schedule 23, and Schedule 25 of the OATT.

Capacity Clearing Price is the clearing price for a Capacity Zone for a Capacity Commitment Period resulting from the Forward Capacity Auction conducted for that Capacity Commitment Period, as determined in accordance with Section III.13.2.7 of Market Rule 1.

Capacity Commitment Period is the one-year period from June 1 through May 31 for which obligations are assumed and payments are made in the Forward Capacity Market.

Capacity Cost (CC) is one of four forms of compensation that may be paid to resources providing VAR Service under Schedule 2 of the OATT.

Capacity Export Through Import Constrained Zone Transaction is defined in Section III.1.10.7(f)(i) of Market Rule 1.

Capacity Load Obligation is the quantity of capacity for which a Market Participant is financially responsible as described in Section III.13.7.5.2 of Market Rule 1.

Capacity Load Obligation Acquiring Participant is a load serving entity or any other Market Participant seeking to acquire a Capacity Load Obligation through a Capacity Load Obligation Bilateral, as described in Section III.13.5.2 of Market Rule 1.

Capacity Network Import Capability (CNI Capability) is as defined in Section I of Schedule 25 of the OATT.

Capacity Network Import Interconnection Service (CNI Interconnection Service) is as defined in Section I of Schedule 25 of the OATT.

Capacity Load Obligation Bilateral is a bilateral contract through which a Market Participant may transfer all or a portion of its Capacity Load Obligation to another entity, as described in Section III.13.5 of Market Rule 1.

Capacity Load Obligation Transferring Participant is an entity that has a Capacity Load Obligation and is seeking to shed such obligation through a Capacity Load Obligation Bilateral, as described in Section III.13.5.2 of Market Rule 1.

Capacity Network Resource (CNR) is defined in Section I of Schedule 22 and Attachment 1 to Schedule 23 of the OATT.

Capacity Network Resource Interconnection Service (CNR Interconnection Service) is defined in Section I of Schedule 22 and Attachment 1 to Schedule 23 of the OATT.

Capacity Performance Bilateral is a transaction for transferring Capacity Performance Score, as described in Section III.13.5.3 of Market Rule 1.

Capacity Performance Payment is the performance-dependent portion of revenue received in the Forward Capacity Market, as described in Section III.13.7.2 of Market Rule 1.

Capacity Performance Payment Rate is a rate used in calculating Capacity Performance Payments, as described in Section III.13.7.2.5 of Market Rule 1.

Capacity Performance Score is a figure used in determining Capacity Performance Payments, as described in Section III.13.7.2.4 of Market Rule 1.

Capacity Rationing Rule addresses whether offers and bids in a Forward Capacity Auction may be rationed, as described in Section III.13.2.6 of Market Rule 1.

Capacity Scarcity Condition is a period during which performance is measured in the Forward Capacity Market, as described in Section III.13.7.2.1 of Market Rule 1.

Capacity Scarcity Condition is a period during which performance is measured in the Forward Capacity Market, as described in Section III.13.7.2.1 of Market Rule 1.

Capacity Supply Obligation is an obligation to provide capacity from a resource, or a portion thereof, to satisfy a portion of the Installed Capacity Requirement that is acquired through a Forward Capacity Auction in accordance with Section III.13.2, a reconfiguration auction in accordance with Section III.13.4, or a Capacity Supply Obligation Bilateral in accordance with Section III.13.5.1 of Market Rule 1.

Capacity Supply Obligation Bilateral is a bilateral contract through which a Market Participant may transfer all or a part of its Capacity Supply Obligation to another entity, as described in Section III.13.5.1 of Market Rule 1.

Capacity Transfer Rights (CTRs) are calculated in accordance with Section III.13.7.5.4.

Capacity Transferring Resource is a resource that has a Capacity Supply Obligation and is seeking to shed such obligation, or a portion thereof, through: (1) a Capacity Supply Obligation Bilateral, as described in Section III.13.5.1, or; (2) an annual or monthly reconfiguration auction, as described in Section III.13.4.

Capacity Zone is a geographic sub-region of the New England Control Area as determined in accordance with Section III.12.4 of Market Rule 1.

Capacity Zone Demand Curves are the demand curves used in the Forward Capacity Market for a Capacity Zone as specified in Sections III.13.2.2.2 and III.13.2.2.3.

Capital Funding Charge (CFC) is defined in Section IV.B.2 of the Tariff.

CARL Data is Control Area reliability data submitted to the ISO to permit an assessment of the ability of an external Control Area to provide energy to the New England Control Area in support of capacity offered to the New England Control Area by that external Control Area.

Category B Designated Blackstart Resource has the same meaning as Designated Blackstart Resource.

Charge is a sum of money due from a Covered Entity to the ISO, either in its individual capacity or as billing and collection agent for NEPOOL pursuant to the Participants Agreement.

CLAIM10 is the value, expressed in megawatts, calculated pursuant to Section III.9.5.3 of the Tariff.

CLAIM30 is the value, expressed in megawatts, calculated pursuant to Section III.9.5.3 of the Tariff.

Claimed Capability Audit is performed to determine the real power output capability of a Generator Asset or the demand reduction capability of a Demand Response Resource.

Cluster Enabling Transmission Upgrade (CETU) has the meaning specified in Section I of Schedule 22, Attachment 1 to Schedule 23, and Section I of Schedule 25 of the OATT.

Cluster Enabling Transmission Upgrade Regional Planning Study (CRPS) has the meaning specified in Section I of Schedule 22, Attachment 1 to Schedule 23, and Section I of Schedule 25 of the OATT.

Cluster Entry Deadline has the meaning specified in Section I of Schedule 22, Attachment 1 to Schedule 23, and Section I of Schedule 25 of the OATT.

Cluster Interconnection System Impact Study (CSIS) has the meaning specified in Section I of Schedule 22, Attachment 1 to Schedule 23, and Section I of Schedule 25 of the OATT.

Clustering has the meaning specified in Section I of Schedule 22, Attachment 1 to Schedule 23, and Section I of Schedule 25 of the OATT.

CNR Capability is defined in Section I of Schedule 22 and Attachment 1 to Schedule 23 of the OATT.

Coincident Peak Contribution is a Market Participant's share of the New England Control Area coincident peak demand for the prior calendar year as determined prior to the start of each Capacity Commitment Period, which reflects the sum of the prior year's annual coincident peak contributions of the customers served by the Market Participant at each Load Asset. Daily Coincident Peak Contribution

values shall be submitted by the Assigned Meter Reader or Host Participant by the meter reading deadline to the ISO.

Commercial Capacity is capacity that has achieved FCM Commercial Operation.

Commission is the Federal Energy Regulatory Commission.

Commitment Period is (i) for a Day-Ahead Energy Market commitment, a period of one or more contiguous hours for which a Resource is cleared in the Day-Ahead Energy Market, and (ii) for a Real-Time Energy Market commitment, the period of time for which the ISO indicates the Resource is being committed when it issues the Dispatch Instruction. If the ISO does not indicate the period of time for which the Resource is being committed in the Real-Time Energy Market, then the Commitment Period is the Minimum Run Time for an offline Resource and one hour for an online Resource.

Common Costs are those costs associated with a Station that are avoided only by the clearing of the Static De-List Bids, the Permanent De-List Bids, or the Retirement De-List Bids of all the Existing Generating Capacity Resources comprising the Station.

Completed Application is an Application that satisfies all of the information and other requirements of the OATT, including any required deposit.

Compliance Effective Date is the date upon which the changes in the predecessor NEPOOL Open Access Transmission Tariff which have been reflected herein to comply with the Commission's Order of April 20, 1998 became effective.

Composite FCM Transaction is a transaction for separate resources seeking to participate as a single composite resource in a Forward Capacity Auction in which multiple Designated FCM Participants provide capacity, as described in Section III.13.1.5 of Market Rule 1.

Conditional Qualified New Resource is defined in Section III.13.1.1.2.3(f) of Market Rule 1.

Confidential Information is defined in Section 2.1 of the ISO New England Information Policy, which is Attachment D to the Tariff.

Confidentiality Agreement is Attachment 1 to the ISO New England Billing Policy.

Congestion is a condition of the New England Transmission System in which transmission limitations prevent unconstrained regional economic dispatch of the power system. Congestion is the condition that results in the Congestion Component of the Locational Marginal Price at one Location being different from the Congestion Component of the Locational Marginal Price at another Location during any given hour of the dispatch day in the Day-Ahead Energy Market or Real-Time Energy Market.

Congestion Component is the component of the nodal price that reflects the marginal cost of congestion at a given Node or External Node relative to the reference point. When used in connection with Zonal Price and Hub Price, the term Congestion Component refers to the Congestion Components of the nodal prices that comprise the Zonal Price and Hub Price weighted and averaged in the same way that nodal prices are weighted to determine Zonal Price and averaged to determine the Hub Price.

Congestion Cost is the cost of congestion as measured by the difference between the Congestion Components of the Locational Marginal Prices at different Locations and/or Reliability Regions on the New England Transmission System.

Congestion Paying LSE is, for the purpose of the allocation of FTR Auction Revenues to ARR Holders as provided for in Appendix C of Market Rule 1, a Market Participant or Non-Market Participant Transmission Customer that is responsible for paying for Congestion Costs as a Transmission Customer paying for Regional Network Service under the Transmission, Markets and Services Tariff, unless such Transmission Customer has transferred its obligation to supply load in accordance with ISO New England System Rules, in which case the Congestion Paying LSE shall be the Market Participant supplying the transferred load obligation. The term Congestion Paying LSE shall be deemed to include, but not be limited to, the seller of internal bilateral transactions that transfer Real-Time Load Obligations under the ISO New England System Rules.

Congestion Revenue Fund is the amount available for payment of target allocations to FTR Holders from the collection of Congestion Cost.

Congestion Shortfall means congestion payments exceed congestion charges during the billing process in any billing period.

Contingency Reserve has the meaning specified in the Glossary of Terms Used in NERC Reliability Standards.

Contingency Reserve Restoration Period has the meaning specified in the Glossary of Terms Used in NERC Reliability Standards.

Continuous Storage ATRR is an ATRR that participates in the New England Markets as part of a Continuous Storage Facility, as described in Section III.1.10.6 of Market Rule 1.

Continuous Storage DARD is a DARD that participates in the New England Markets as part of a Continuous Storage Facility, as described in Section III.1.10.6 of Market Rule 1.

Continuous Storage Generator Asset is a Generator Asset that participates in the New England Markets as part of a Continuous Storage Facility, as described in Section III.1.10.6 of Market Rule 1.

Continuous Storage Facility is a type of Electric Storage Facility, as described in Section III.1.10.6 of Market Rule 1.

Control Agreement is the document posted on the ISO website that is required if a Market Participant's cash collateral is to be invested in BlackRock funds.

Control Area is an electric power system or combination of electric power systems to which a common automatic generation control scheme is applied in order to:

(1) match, at all times, the power output of the generators within the electric power system(s) and capacity and energy purchased from entities outside the electric power system(s), with the load within the electric power system(s);

(2) maintain scheduled interchange with other Control Areas, within the limits of Good Utility Practice;

(3) maintain the frequency of the electric power system(s) within reasonable limits in accordance with Good Utility Practice and the criteria of the applicable regional reliability council or the North American Electric Reliability Corporation; and

(4) provide sufficient generating capacity to maintain operating reserves in accordance with Good Utility Practice.

Controllable Behind-the-Meter Generation means generation whose output can be controlled located at the same facility as a DARD or a Demand Response Asset, excluding: (1) generators whose output is separately metered and reported and (2) generators that cannot operate electrically synchronized to, and that are operated only when the facility loses its supply of power from, the New England Transmission System, or when undergoing related testing.

Coordinated External Transaction is an External Transaction at an external interface for which the enhanced scheduling procedures in Section III.1.10.7.A are implemented. A transaction to wheel energy into, out of or through the New England Control Area is not a Coordinated External Transaction.

Coordinated Transaction Scheduling means the enhanced scheduling procedures set forth in Section III.1.10.7.A.

Correction Limit means the date that is one hundred and one (101) calendar days from the last Operating Day of the month to which the data applied. As described in Section III.3.6.1 of Market Rule 1, this will be the period during which meter data corrections must be submitted unless they qualify for submission as a Requested Billing Adjustment under Section III.3.7 of Market Rule 1.

Cost of Energy Consumed (CEC) is one of four forms of compensation that may be paid to resources providing VAR Service under Schedule 2 of the OATT.

Cost of Energy Produced (CEP) is one of four forms of compensation that may be paid to resources providing VAR Service under Schedule 2 of the OATT.

Cost of New Entry (CONE) is the estimated cost of new entry ($/kW-month) for a capacity resource that is determined by the ISO for each Forward Capacity Auction pursuant to Section III.13.2.4.

Counterparty means the status in which the ISO acts as the contracting party, in its name and own right and not as an agent, to an agreement or transaction with a Customer (including assignments involving Customers) involving sale to the ISO, and/or purchase from the ISO, of Regional Transmission Service and market and other products and services, and other transactions and assignments involving Customers, all as described in the Tariff.

Covered Entity is defined in the ISO New England Billing Policy.

Credit Coverage is third-party credit protection obtained by the ISO, in the form of credit insurance coverage, a performance or surety bond, or a combination thereof.

Credit Qualifying means a Rated Market Participant that has an Investment Grade Rating and an Unrated Market Participant that satisfies the Credit Threshold.

Credit Threshold consists of the conditions for Unrated Market Participants outlined in Section II.B.2 of the ISO New England Financial Assurance Policy.

Critical Energy Infrastructure Information (CEII) is defined in Section 3.0(j) of the ISO New England Information Policy, which is Attachment D to the Tariff.

Current Ratio is, on any date, all of a Market Participant's or Non-Market Participant Transmission Customer's current assets divided by all of its current liabilities, in each case as shown on the most recent financial statements provided by such Market Participant or Non-Market Participant Transmission Customer to the ISO.

Curtailment is a reduction in the dispatch of a transaction that was scheduled, using transmission service, in response to a transfer capability shortage as a result of system reliability conditions.

Customer is a Market Participant, a Transmission Customer or another customer of the ISO.

Data Reconciliation Process means the process by which meter reconciliation and data corrections that are discovered by Governance Participants after the Invoice has been issued for a particular month or that are discovered prior to the issuance of the Invoice for the relevant month but not included in that Invoice or in the other Invoices for that month and are reconciled by the ISO on an hourly basis based on data submitted to the ISO by the Host Participant Assigned Meter Reader or Assigned Meter Reader.

Day-Ahead is the calendar day immediately preceding the Operating Day.

Day-Ahead Adjusted Load Obligation is defined in Section III.3.2.1(a)(1) of Market Rule 1.

Day-Ahead Ancillary Services means Day-Ahead Generation Contingency Reserve, Day-Ahead Replacement Energy Reserve, and Day-Ahead Energy Imbalance Reserve.

Day-Ahead Congestion Revenue is defined in Section III.3.2.1(i) of Market Rule 1.

Day-Ahead Demand Reduction Obligation is defined in Section III.3.2.1(a)(1) of Market Rule 1.

Day-Ahead Energy Imbalance Reserve is a form of reserve capability that is procured in the Day-Ahead Energy Market to help satisfy the Forecast Energy Requirement Demand Quantity described in Section III.1.8.6 of Market Rule 1.

Day-Ahead Energy Imbalance Reserve Demand Quantity is described in Section III.1.8.5(f) of Market Rule 1.

Day-Ahead Energy Imbalance Reserve Obligation is defined in Section III.3.2.1(a)(2) of Market Rule 1.

Day-Ahead Energy Market means: (i) prior to June 1, 2024, the schedule of commitments for the purchase or sale of energy, purchase of demand reductions, payment of Congestion Costs, and payment for losses developed by the ISO as a result of the offers and specifications submitted in accordance with Section III.1.10 of Market Rule 1, and (ii) commencing on June 1, 2024, the schedule of commitments for the purchase or sale of energy, the sale of ancillary services, purchase of demand reductions, payment of Congestion Costs, and payment for losses developed by the ISO as a result of the offers and specifications submitted in accordance with Sections III.1.8 and III.1.10 of Market Rule 1.

Day-Ahead Energy Market Congestion Charge/Credit is defined in Section III.3.2.1(f) of Market Rule 1.

Day-Ahead Energy Market Energy Charge/Credit is defined in Section III.3.2.1(f) of Market Rule 1.

Day-Ahead Energy Market Loss Charge/Credit is defined in Section III.3.2.1(f) of Market Rule 1.

Day-Ahead Energy Market NCPC Credit is an NCPC Credit calculated pursuant to Appendix F to Market Rule 1.

Day-Ahead External Transaction Export and Decrement Bid NCPC Credit is an NCPC Credit calculated pursuant to Appendix F to Market Rule 1.

Day-Ahead External Transaction Import and Increment Offer NCPC Credit is an NCPC Credit calculated pursuant to Appendix F to Market Rule 1.

Day-Ahead Four-Hour Reserve is a form of reserve capability that is procured in the Day-Ahead Energy Market based on the system-wide requirements described in Section III.1.8.5 of Market Rule 1.

Day-Ahead Four-Hour Reserve Obligation is defined in Section III.3.2.1(a)(2) of Market Rule 1.

Day-Ahead Generation Contingency Reserve means Day-Ahead Ten-Minute Spinning Reserve, Day-Ahead Ten-Minute Non-Spinning Reserve, and Day-Ahead Thirty-Minute Operating Reserve.

Day-Ahead Generation Obligation is defined in Section III.3.2.1(a)(1) of Market Rule 1.

Day-Ahead Load Obligation is defined in Section III.3.2.1(a)(1) of Market Rule 1.

Day-Ahead Locational Adjusted Net Interchange is defined in Section III.3.2.1(a)(1) of Market Rule 1.

Day-Ahead Loss Charges or Credits is defined in Section III.3.2.1(k) of Market Rule 1.

Day-Ahead Loss Revenue is defined in Section III.3.2.1(j) of Market Rule 1.

Day-Ahead Ninety-Minute Reserve is a form of reserve capability that is procured in the Day-Ahead Energy Market based on the system-wide requirements described in Section III.1.8.5 of Market Rule 1.

Day-Ahead Ninety-Minute Reserve Obligation is defined in Section III.3.2.1(a)(2) of Market Rule 1.

Day-Ahead Prices means the Locational Marginal Prices resulting from the Day-Ahead Energy Market, and commencing on June 1, 2024, the additional prices resulting from the Day-Ahead Energy Market described in Section III.2.6.2 of Market Rule 1.

Day-Ahead Replacement Energy Reserve means Day-Ahead Ninety-Minute Reserve and Day-Ahead Four-Hour Reserve.

Day-Ahead Ten-Minute Non-Spinning Reserve is a form of ten-minute reserve capability that is procured in the Day-Ahead Energy Market based on the system-wide requirements described in Section III.1.8.5 of Market Rule 1.

Day-Ahead Ten-Minute Non-Spinning Reserve Obligation is defined in Section III.3.2.1(a)(2) of Market Rule 1.

Day-Ahead Ten-Minute Spinning Reserve is a form of ten-minute reserve capability that is procured in the Day-Ahead Energy Market based on the system-wide requirements described in Section III.1.8.5 of Market Rule 1.

Day-Ahead Ten-Minute Spinning Reserve Demand Quantity is described in Section III.1.8.5(a) of Market Rule 1.

Day-Ahead Ten-Minute Spinning Reserve Obligation is defined in Section III.3.2.1(a)(2) of Market Rule 1.

Day-Ahead Thirty-Minute Operating Reserve is a form of reserve capability that is procured in the Day-Ahead Energy Market based on the system-wide requirements described in Section III.1.8.5 of Market Rule 1.

Day-Ahead Thirty-Minute Operating Reserve Obligation is defined in Section III.3.2.1(a)(2) of Market Rule 1.

Day-Ahead Total Four-Hour Reserve Demand Quantity is described in Section III.1.8.5(e) of Market Rule 1.

Day-Ahead Total Ninety-Minute Reserve Demand Quantity is described in Section III.1.8.5(d) of Market Rule 1.

Day-Ahead Total Ten-Minute Reserve Demand Quantity is described in Section III.1.8.5(b) of Market Rule 1.

Day-Ahead Total Thirty-Minute Operating Reserve Demand Quantity is described in Section III.1.8.5(c) of Market Rule 1.

DDP Dispatchable Resource is any Dispatchable Resource that the ISO dispatches using Desired Dispatch Points in the Resource's Dispatch Instructions.

Debt-to-Total Capitalization Ratio is, on any date, a Market Participant's or Non-Market Participant Transmission Customer's total debt (including all current borrowings) divided by its total shareholders' equity plus total debt, in each case as shown on the most recent financial statements provided by such Market Participant or Non-Market Participant Transmission Customer to the ISO.

Decrement Bid means a bid to purchase energy at a specified Location in the Day-Ahead Energy Market which is not associated with a physical load. An accepted Decrement Bid results in scheduled load at the specified Location in the Day-Ahead Energy Market.

Default Amount is all or any part of any amount due to be paid by any Covered Entity that the ISO, in its reasonable opinion, believes will not or has not been paid when due (other than in the case of a payment dispute for any amount due for transmission service under the OATT).

Default Period is defined in Section 3.3.h(i) of the ISO New England Billing Policy.

Delivering Party is the entity supplying capacity and/or energy to be transmitted at Point(s) of Receipt under the OATT.

Demand Bid means a request to purchase an amount of energy, at a specified Location, or an amount of energy at a specified price, that is associated with a physical load. A cleared Demand Bid in the Day-Ahead Energy Market results in scheduled load at the specified Location. Demand Bids submitted for use in the Real-Time Energy Market are specific to Dispatchable Asset Related Demands only.

Demand Bid Block-Hours are the Block-Hours assigned to the submitting Customer for each Demand Bid.

Demand Bid Cap is $2,000/MWh.

Demand Capacity Resource means an Existing Demand Capacity Resource or a New Demand Capacity Resource. There are three Demand Capacity Resource types: Active Demand Capacity Resources, On-Peak Demand Resources, and Seasonal Peak Demand Resources.

Demand Designated Entity is the entity designated by a Market Participant to receive Dispatch Instructions for Demand Response Resources in accordance with the provisions set forth in ISO New England Operating Procedure No. 14.

Demand Reduction Offer is an offer by a Market Participant with a Demand Response Resource to reduce demand.

Demand Reduction Offer Block-Hours are Block-Hours assigned to the Lead Market Participant for each Demand Reduction Offer. Blocks of the Demand Reduction Offer in effect for each hour will be totaled to determine the quantity of Demand Reduction Offer Block-Hours for a given day. In the case that a Resource has a Real-Time unit status of "unavailable" for the entire day, that day will not contribute to the quantity of Demand Reduction Offer Block-Hours. However, if the Resource has at least one hour of the day with a unit status of "available," the entire day will contribute to the quantity of Demand Reduction Offer Block-Hours.

Demand Reduction Threshold Price is a minimum offer price calculated pursuant to Section III.1.10.1A(f).

Demand Resource On-Peak Hours are hours ending 1400 through 1700, Monday through Friday on non-Demand Response Holidays during the months of June, July, and August and hours ending 1800 through 1900, Monday through Friday on non-Demand Response Holidays during the months of December and January.

Demand Resource Seasonal Peak Hours are those hours in which the actual, real-time hourly load, as measured using real-time telemetry (adjusted for transmission and distribution losses, and excluding load associated with Exports and Storage DARDs) for Monday through Friday on non-Demand Response Holidays, during the months of June, July, August, December, and January, as determined by the ISO, is

equal to or greater than 90% of the most recent 50/50 system peak load forecast, as determined by the ISO, for the applicable summer or winter season.

Demand Response Asset is an asset comprising the demand reduction capability of an individual end-use customer at a Retail Delivery Point or the aggregated demand reduction capability of multiple end-use customers from multiple delivery points (as described in Section III.8.1.1(f)) that has been registered in accordance with III.8.1.1.

Demand Response Available is the capability of the Demand Response Resource, in whole or in part, at any given time, to reduce demand in response to a Dispatch Instruction.

Demand Response Baseline is the expected baseline demand of an individual end-use metered customer or group of end-use metered customers as determined pursuant to Section III.8.2.

Demand Response Holiday is New Year's Day, Memorial Day, Independence Day, Labor Day, Veterans Day, Thanksgiving Day, and Christmas Day. If the holiday falls on a Saturday, the holiday will be observed on the preceding Friday; if the holiday falls on a Sunday, the holiday will be observed on the following Monday.

Demand Response Resource is an individual Demand Response Asset or aggregation of Demand Response Assets within a DRR Aggregation Zone that has been registered in accordance with Section III.8.1.2.

Demand Response Resource Notification Time is the period of time between the receipt of a startup Dispatch Instruction and the time the Demand Response Resource starts reducing demand.

Demand Response Resource Ramp Rate is the average rate, expressed in MW per minute, at which the Demand Response Resource can reduce demand.

Demand Response Resource Start-Up Time is the period of time between the time a Demand Response Resource starts reducing demand at the conclusion of the Demand Response Resource Notification Time and the time the resource can reach its Minimum Reduction and be ready for further dispatch by the ISO.

Designated Agent is any entity that performs actions or functions required under the OATT on behalf of the ISO, a Transmission Owner, a Schedule 20A Service Provider, an Eligible Customer, or a Transmission Customer.

Designated Blackstart Resource is a resource that meets the eligibility requirements specified in Schedule 16 of the OATT, which includes any resource referred to previously as a Category B Designated Blackstart Resource.

Designated Entity is the entity designated by a Market Participant to receive Dispatch Instructions for a Generator Asset and/or Dispatchable Asset Related Demand in accordance with the provisions set forth in ISO New England Operating Procedure No. 14.

Designated FCM Participant is any Lead Market Participant, including any Provisional Member that is a Lead Market Participant, transacting in any Forward Capacity Auction, reconfiguration auctions or Capacity Supply Obligation Bilateral for capacity that is otherwise required to provide additional financial assurance under the ISO New England Financial Assurance Policy.

Designated FTR Participant is a Market Participant, including FTR-Only Customers, transacting in the FTR Auction that is otherwise required to provide additional financial assurance under the ISO New England Financial Assurance Policy.

Desired Dispatch Point (DDP) means the control signal, expressed in megawatts, transmitted to direct the output, consumption, or demand reduction level of each Generator Asset, Dispatchable Asset Related Demand, or Demand Response Resource dispatched by the ISO in accordance with the asset's Offer Data.

Direct Assignment Facilities are facilities or portions of facilities that are constructed for the sole use/benefit of a particular Transmission Customer requesting service under the OATT or a Generator Owner requesting an interconnection. Direct Assignment Facilities shall be specified in a separate agreement among the ISO, Interconnection Customer and Transmission Customer, as applicable, and the Transmission Owner whose transmission system is to be modified to include and/or interconnect with the Direct Assignment Facilities, shall be subject to applicable Commission requirements, and shall be paid for by the Customer in accordance with the applicable agreement and the Tariff.

Directly Metered Assets are specifically measured by OP-18 compliant metering as currently described in Section IV (Metering and Recording for Settlements) of OP-18. Directly Metered Assets include all Tie-Line Assets, all Generator Assets, as well as some Load Assets. Load Assets for which the Host Participant is not the Assigned Meter Reader are considered Directly Metered Assets. In addition, the Host Participant Assigned Meter Reader determines which additional Load Assets are considered Directly Metered Assets and which ones are considered Profiled Load Assets based upon the Host Participant Assigned Meter Reader reporting systems and process by which the Host Participant Assigned Meter Reader allocates non-PTF losses.

Disbursement Agreement is the Rate Design and Funds Disbursement Agreement among the PTOs, as amended and restated from time to time.

Dispatch Instruction means directions given by the ISO to Market Participants, which may include instructions to start up, shut down, raise or lower generation, curtail or restore loads from Demand Response Resources, change External Transactions, or change the status or consumption of a Dispatchable Asset Related Demand in accordance with the Supply Offer, Demand Bid, or Demand Reduction Offer parameters. Such instructions may also require a change to the operation of a Pool Transmission Facility. Such instructions are given through either electronic or verbal means.

Dispatch Zone means a subset of Nodes located within a Load Zone established by the ISO for each Capacity Commitment Period pursuant to Section III.12.4A.

Dispatchable Asset Related Demand (DARD) is an Asset Related Demand that is capable of having its energy consumption modified in Real-Time in response to Dispatch Instructions. A DARD must be capable of receiving and responding to electronic Dispatch Instructions, must be able to increase or decrease energy consumption between its Minimum Consumption Limit and Maximum Consumption Limit in accordance with Dispatch Instructions, and must meet the technical requirements specified in the ISO New England Operating Procedures and Manuals.

Dispatchable Resource is any Generator Asset, Dispatchable Asset Related Demand, Demand Response Resource, or, with respect to the Regulation Market only, Alternative Technology Regulation Resource, that, during the course of normal operation, is capable of receiving and responding to electronic Dispatch Instructions in accordance with the parameters contained in the Resource's Supply Offer, Demand Bid, Demand Reduction Offer or Regulation Service Offer. A Resource that is normally classified as a

Dispatchable Resource remains a Dispatchable Resource when it is temporarily not capable of receiving and responding to electronic Dispatch Instructions.

Dispute Representatives are defined in 6.5.c of the ISO New England Billing Policy.

Disputed Amount is a Covered Entity's disputed amount due on any fully paid monthly Invoice and/or any amount believed to be due or owed on a Remittance Advice, as defined in Section 6 of the ISO New England Billing Policy.

Disputing Party, for the purposes of the ISO New England Billing Policy, is any Covered Entity seeking to recover a Disputed Amount.

Distributed Generation means generation directly connected to end-use customer load and located behind the end-use customer's Retail Delivery Point that reduces the amount of energy that would otherwise have been produced on the electricity network in the New England Control Area, provided that the facility's Net Supply Capability is (i) less than 5 MW or (ii) less than or equal to the Maximum Facility Load, whichever is greater.

DRR Aggregation Zone is a Dispatch Zone entirely within a single Reserve Zone or Rest of System or, where a Dispatch Zone is not entirely within a single Reserve Zone or Rest of System, each portion of the Dispatch Zone demarcated by the Reserve Zone boundary.

Do Not Exceed (DNE) Dispatchable Generator is any Generator Asset that is dispatched using Do Not Exceed Dispatch Points in its Dispatch Instructions and meets the criteria specified in Section III.1.11.3(e). Do Not Exceed Dispatchable Generators are Dispatchable Resources.

Do Not Exceed Dispatch Point is a Dispatch Instruction indicating a maximum output level that a DNE Dispatchable Generator must not exceed.

Dynamic De-List Bid is a bid that may be submitted by Existing Generating Capacity Resources, Existing Import Capacity Resources, and Existing Demand Capacity Resources in the Forward Capacity Auction below the Dynamic De-List Bid Threshold, as described in Section III.13.2.3.2(d) of Market Rule 1.

Dynamic De-List Bid Threshold is the price specified in Section III.13.1.2.3.1.A of Market Rule 1 associated with the submission of Dynamic De-List Bids in the Forward Capacity Auction.

EA Amount is defined in Section IV.B.2.2 of the Tariff.

Early Amortization Charge (EAC) is defined in Section IV.B.2 of the Tariff.

Early Amortization Working Capital Charge (EAWCC) is defined in Section IV.B.2 of the Tariff.

Early Payment Shortfall Funding Amount (EPSF Amount) is defined in Section IV.B.2.4 of the Tariff.

Early Payment Shortfall Funding Charge (EPSFC) is defined in Section IV.B.2 of the Tariff.

EAWW Amount is defined in Section IV.B.2.3 of the Tariff.

EBITDA-to-Interest Expense Ratio is, on any date, a Market Participant's or Non-Market Participant Transmission Customer's earnings before interest, taxes, depreciation and amortization in the most recent fiscal quarter divided by that Market Participant's or Non-Market Participant Transmission Customer's expense for interest in that fiscal quarter, in each case as shown on the most recent financial statements provided by such Market Participant or Non-Market Participant Transmission Customer to the ISO.

Economic Dispatch Point is the output, reduction, or consumption level to which a Resource would have been dispatched, based on the Resource's Supply Offer, Demand Reduction Offer, or Demand Bid and the Real-Time Price, and taking account of any operating limits, had the ISO not dispatched the Resource to another Desired Dispatch Point.

Economic Maximum Limit or Economic Max is the maximum available output, in MW, of a Generator Asset that a Market Participant offers to supply in the Day-Ahead Energy Market or Real-Time Energy Market, as reflected in the Generator Asset's Offer Data. This represents the highest MW output a Market Participant has offered for a Generator Asset for economic dispatch. A Market Participant must maintain an up-to-date Economic Maximum Limit (and where applicable, must provide the ISO with any telemetry required by ISO New England Operating Procedure No. 18 to allow the ISO to maintain an

updated Economic Maximum Limit) for all hours in which a Generator Asset has been offered into the Day-Ahead Energy Market or Real-Time Energy Market.

Economic Minimum Limit or Economic Min is (a) for a Generator Asset with an incremental heat rate, the maximum of: (i) the lowest sustainable output level as specified by physical design characteristics, environmental regulations or licensing limits; and (ii) the lowest sustainable output level at which a one MW increment increase in the output level would not decrease the incremental cost, calculated based on the incremental heat rate, of providing an additional MW of output, and (b) for a Generator Asset without an incremental heat rate, the lowest sustainable output level that is consistent with the physical design characteristics of the Generator Asset and with meeting all environmental regulations and licensing limits, and (c) for a Generator Asset undergoing Facility and Equipment Testing or auditing, the level to which the Generator Asset requests and is approved to operate or is directed to operate for purposes of completing the Facility and Equipment Testing or auditing, and (d) for Non-Dispatchable Resources the output level at which a Market Participant anticipates its Non-Dispatchable Resource will be available to operate based on fuel limitations, physical design characteristics, environmental regulations or licensing limits.

Economic Study is defined in Section 4.1(b) of Attachment K to the OATT.

Effective Offer is the Supply Offer, Demand Reduction Offer, or Demand Bid that is used for NCPC calculation purposes as specified in Section III.F.1(a).

EFT is electronic funds transfer.

Elective Transmission Upgrade is defined in Section I of Schedule 25 of the OATT.

Elective Transmission Upgrade Interconnection Customer is defined in Schedule 25 of the OATT.

Electric Reliability Organization (ERO) is defined in 18 C.F.R. § 39.1.

Electric Storage Facility is a storage facility that participates in the New England Markets as described in Section III.1.10.6 of Market Rule 1.

Eligible Customer is: (i) Any entity that is engaged, or proposes to engage, in the wholesale or retail electric power business is an Eligible Customer under the OATT. (ii) Any electric utility (including any power marketer), Federal power marketing agency, or any other entity generating electric energy for sale or for resale is an Eligible Customer under the OATT. Electric energy sold or produced by such entity may be electric energy produced in the United States, Canada or Mexico. However, with respect to transmission service that the Commission is prohibited from ordering by Section 212(h) of the Federal Power Act, such entity is eligible only if the service is provided pursuant to a state requirement that the Transmission Owner with which that entity is directly interconnected or the distribution company having the service territory in which that entity is located (if that entity is a retail customer) offer the unbundled transmission service or Local Delivery Service, or pursuant to a voluntary offer of such service by the Transmission Owner with which that entity is directly interconnected or the distribution company having the service territory in which that entity is located (if that entity is a retail customer). (iii) Any end user taking or eligible to take unbundled transmission service or Local Delivery Service pursuant to a state requirement that the Transmission Owner with which that end user is directly interconnected or the distribution company having the service territory in which that entity is located (if that entity is a retail customer) offer the transmission service or Local Delivery Service, or pursuant to a voluntary offer of such service by the Transmission Owner with which that end user is directly interconnected, or the distribution company having the service territory in which that entity is located (if that entity is a retail customer) is an Eligible Customer under the OATT.

Eligible FTR Bidder is an entity that has satisfied applicable financial assurance criteria, and shall not include the auctioneer, its Affiliates, and their officers, directors, employees, consultants and other representatives.

Emergency is an abnormal system condition on the bulk power systems of New England or neighboring Control Areas requiring manual or automatic action to maintain system frequency, or to prevent the involuntary loss of load, equipment damage, or tripping of system elements that could adversely affect the reliability of an electric system or the safety of persons or property; or a fuel shortage requiring departure from normal operating procedures in order to minimize the use of such scarce fuel; or a condition that requires implementation of Emergency procedures as defined in the ISO New England Manuals.

Emergency Condition means an Emergency has been declared by the ISO in accordance with the procedures set forth in the ISO New England Manuals and ISO New England Administrative Procedures.

Emergency Energy is energy transferred from one control area operator to another in an Emergency.

Emergency Minimum Limit or Emergency Min means the minimum output, in MWs, that a Generator Asset can deliver for a limited period of time without exceeding specified limits of equipment stability and operating permits.

EMS is energy management system.

End-of-Round Price is the lowest price associated with a round of a Forward Capacity Auction, as described in Section III.13.2.3.1 of Market Rule 1.

End User Participant is defined in Section 1 of the Participants Agreement.

Energy is power produced in the form of electricity, measured in kilowatthours or megawatthours.

Energy Administration Service (EAS) is the service provided by the ISO, as described in Schedule 2 of Section IV.A of the Tariff.

Energy Call Option Offer is a form of offer that may be submitted by Market Participants in the Day-Ahead Energy Market in accordance with Section III.1.8 of Market Rule 1, and that is used by the ISO to determine obligations for Day-Ahead Ancillary Services as defined in Section III.3.2.1(a)(2) of Market Rule 1.

Energy Call Option Strike Price is specified in Section III.1.8. 3 of Market Rule 1.

Energy Component means the Locational Marginal Price at the reference point.

Energy Efficiency is installed measures (e.g., products, equipment, systems, services, practices and/or strategies) on end-use customer facilities that reduce the total amount of electrical energy needed, while delivering a comparable or improved level of end-use service. Such measures include, but are not limited to, the installation of more energy efficient lighting, motors, refrigeration, HVAC equipment and control systems, envelope measures, operations and maintenance procedures, and industrial process equipment.

Energy Imbalance Service is the form of Ancillary Service described in Schedule 4 of the OATT.

Energy Market is, collectively, the Day-Ahead Energy Market and the Real-Time Energy Market.

Energy Non-Zero Spot Market Settlement Hours are the sum of the hours for which the Customer has a positive or negative Real-Time System Adjusted Net Interchange or for which the Customer has a positive or negative Real-Time Demand Reduction Obligation as determined by the ISO settlement process for the Energy Market.

Energy Offer Floor is negative $150/MWh.

Energy Transaction Units (Energy TUs) are the sum for the month for a Customer of Bilateral Contract Block-Hours, Demand Bid Block-Hours, Asset Related Demand Bid Block-Hours, Supply Offer Block-Hours, Demand Reduction Offer Block-Hours, and Energy Non-Zero Spot Market Settlement Hours.

Equipment Damage Reimbursement is the compensation paid to the owner of a Designated Blackstart Resource as specified in Section 5.5 of Schedule 16 to the OATT.

Equivalent Demand Forced Outage Rate (EFORd) means the portion of time a unit is in demand, but is unavailable due to forced outages.

Estimated Capacity Load Obligation is, for the purposes of the ISO New England Financial Assurance Policy, a Market Participant's share of Zonal Capacity Obligation from the latest available month, adjusted as appropriate to account for any relevant Capacity Load Obligation Bilaterals, HQICCs, and Self-Supplied FCA Resource designations for the applicable month.

Establish Claimed Capability Audit is the audit performed pursuant to Section III.1.5.1.2.

Excepted Transaction is a transaction specified in Section II.40 of the Tariff for the applicable period specified in that Section.

Existing Capacity Qualification Deadline is a deadline, specified in Section III.13.1.10 of Market Rule 1, for submission of certain qualification materials for the Forward Capacity Auction, as discussed in Section III.13.1 of Market Rule 1.

Existing Capacity Qualification Package is information submitted for certain existing resources prior to participation in the Forward Capacity Auction, as described in Section III.13.1 of Market Rule 1.

Existing Capacity Resource is any resource that does not meet any of the eligibility criteria to participate in the Forward Capacity Auction as a New Capacity Resource.

Existing Capacity Retirement Deadline is a deadline, specified in Section III.13.1.10 of Market Rule 1, for submission of certain qualification materials for the Forward Capacity Auction, as discussed in Section III.13.1 of Market Rule 1.

Existing Capacity Retirement Package is information submitted for certain existing resources prior to participation in the Forward Capacity Auction, as described in Section III.13.1 of Market Rule 1.

Existing Demand Capacity Resource is a type of Demand Capacity Resource participating in the Forward Capacity Market, as defined in Section III.13.1.4.2 of Market Rule 1.

Existing Generating Capacity Resource is a type of resource participating in the Forward Capacity Market, as defined in Section III.13.1.2.1 of Market Rule 1.

Existing Import Capacity Resource is a type of resource participating in the Forward Capacity Market, as defined in Section III.13.1.3.1 of Market Rule 1.

Expedited Study Request is defined in Section II.34.7 of the OATT.

Export-Adjusted LSR is as defined in Section III.12.4(b)(ii).

Export Bid is a bid that may be submitted by certain resources in the Forward Capacity Auction to export capacity to an external Control Area, as described in Section III.13.1.2.3.1.3 of Market Rule 1.

Exports are Real-Time External Transactions, which are limited to sales from the New England Control Area, for exporting energy out of the New England Control Area.

External Elective Transmission Upgrade (External ETU) is defined in Section I of Schedule 25 of the OATT.

External Market Monitor means the person or entity appointed by the ISO Board of Directors pursuant to Section III.A.1.2 of Appendix A of Market Rule 1 to carry out the market monitoring and mitigation functions specified in Appendix A and elsewhere in Market Rule 1.

External Node is a proxy bus or buses used for establishing a Locational Marginal Price for energy received by Market Participants from, or delivered by Market Participants to, a neighboring Control Area or for establishing Locational Marginal Prices associated with energy delivered through the New England Control Area by Non-Market Participants for use in calculating Non-Market Participant Congestion Costs and loss costs.

External Resource means a generation resource located outside the metered boundaries of the New England Control Area.

External Transaction is the import of external energy into the New England Control Area by a Market Participant or the export of internal energy out of the New England Control Area by a Market Participant in the Day-Ahead Energy Market and/or Real-Time Energy Market, or the wheeling of external energy through the New England Control Area by a Market Participant or a Non-Market Participant in the Real-Time Energy Market.

External Transaction Cap is $2,000/MWh for External Transactions other than Coordinated External Transactions and $1,000/MWh for Coordinated External Transactions.

External Transaction Floor is the Energy Offer Floor for External Transactions other than Coordinated External Transactions and negative $1,000/MWh for Coordinated External Transactions.

External Transmission Project is a transmission project comprising facilities located wholly outside the New England Control Area and regarding which an agreement has been reached whereby New England ratepayers will support all or a portion of the cost of the facilities.

Facilities Study is an engineering study conducted pursuant to the OATT by the ISO (or, in the case of Local Service or interconnections to Local Area Facilities as defined in the TOA, by one or more affected PTOs) or some other entity designated by the ISO in consultation with any affected Transmission Owner(s), to determine the required modifications to the PTF and Non-PTF, including the cost and

scheduled completion date for such modifications, that will be required to provide a requested transmission service or interconnection on the PTF and Non-PTF.

Facility and Equipment Testing means operation of a Resource to evaluate the functionality of the facility or equipment utilized in the operation of the facility.

Failure to Maintain Blackstart Capability is a failure of a Blackstart Owner or Designated Blackstart Resource to meet the Blackstart Service Minimum Criteria or Blackstart Service obligations, but does not include a Failure to Perform During a System Restoration event.

Failure to Perform During a System Restoration is a failure of a Blackstart Owner or Designated Blackstart Resource to follow ISO or Local Control Center dispatch instructions or perform in accordance with the dispatch instructions or the Blackstart Service Minimum Criteria and Blackstart Service obligations, described within the ISO New England Operating Documents, during a restoration of the New England Transmission System.

Fast Start Demand Response Resource is a Demand Response Resource that meets the following criteria: (i) Minimum Reduction Time does not exceed one hour; (ii) Minimum Time Between Reductions does not exceed one hour; (iii) Demand Response Resource Start-Up Time plus Demand Response Resource Notification Time does not exceed 30 minutes; (iv) has personnel available to respond to Dispatch Instructions or has automatic remote response capability; and (v) is capable of receiving and acknowledging a Dispatch Instruction electronically.

Fast Start Generator means a Generator Asset that the ISO can dispatch to an on-line or off-line state through electronic dispatch and that meets the following criteria: (i) Minimum Run Time does not exceed one hour; (ii) Minimum Down Time does not exceed one hour; (iii) cold Notification Time plus cold Start-Up Time does not exceed 30 minutes; (iv) available for dispatch (when it is either in an on-line or off-line state) and manned or has automatic remote dispatch capability; and (v) capable of receiving and acknowledging a start-up or shut-down Dispatch Instruction electronically.

FCA Cleared Export Transaction is defined in Section III.1.10.7(f)(ii) of Market Rule 1.

FCA Qualified Capacity is the Qualified Capacity that is used in a Forward Capacity Auction.

FCM Capacity Charge Requirements are calculated in accordance with Section VII.C of the ISO New England Financial Assurance Policy.

FCM Charge Rate is calculated in accordance with Section VII.C of the ISO New England Financial Assurance Policy.

FCM Commercial Operation is defined in Section III.13.3.8 of Market Rule 1.

FCM Deposit is calculated in accordance with Section VII.B.1 of the ISO New England Financial Assurance Policy.

FCM Financial Assurance Requirements are described in Section VII of the ISO New England Financial Assurance Policy.

Final Forward Reserve Obligation is calculated in accordance with Section III.9.8(a) of Market Rule 1.

Financial Assurance Default results from a Market Participant or Non-Market Participant Transmission Customer's failure to comply with the ISO New England Financial Assurance Policy.

Financial Assurance Obligations relative to the ISO New England Financial Assurance Policy are determined in accordance with Section III.A(v) of the ISO New England Financial Assurance Policy.

Financial Transmission Right (FTR) is a financial instrument that evidences the rights and obligations specified in Sections III.5.2.2 and III.7 of the Tariff.

Firm Point-To-Point Service is service which is arranged for and administered between specified Points of Receipt and Delivery in accordance with Part II.C of the OATT.

Firm Transmission Service is Regional Network Service, Through or Out Service, service for Excepted Transactions, firm MTF Service, firm OTF Service, and firm Local Service.

Flexible DNE Dispatchable Generator is any DNE Dispatchable Generator that meets the following criteria: (i) Minimum Run Time does not exceed one hour; (ii) Minimum Down Time does not exceed one hour; and (iii) cold Notification Time plus cold Start-Up Time does not exceed 30 minutes.

Force Majeure - An event of Force Majeure means any act of God, labor disturbance, act of the public enemy or terrorists, war, invasion, insurrection, riot, fire, storm or flood, ice, explosion, breakage or accident to machinery or equipment, any curtailment, order, regulation or restriction imposed by governmental military or lawfully established civilian authorities, or any other cause beyond the control of the ISO, a Transmission Owner, a Schedule 20A Service Provider, or a Customer, including without limitation, in the case of the ISO, any action or inaction by a Customer, a Schedule 20A Service Provider, or a Transmission Owner, in the case of a Transmission Owner, any action or inaction by the ISO, any Customer, a Schedule 20A Service Provider, or any other Transmission Owner, in the case of a Schedule 20A Service Provider, any action or inaction by the ISO, any Customer, a Transmission Owner, or any other Schedule 20A Service Provider, and, in the case of a Transmission Customer, any action or inaction by the ISO, a Schedule 20A Service Provider, or any Transmission Owner.

Forecast Energy Requirement Demand Quantity is described in Section III.1.8.6 of Market Rule 1.

Forecast Energy Requirement Price is determined in accordance with Section III.2.6.2(a) of Market Rule 1.

Formal Warning is defined in Section III.B.4.1.1 of Appendix B of Market Rule 1.

Formula-Based Sanctions are defined in Section III.B.4.1.3 of Appendix B of Market Rule 1.

Forward Capacity Auction (FCA) is the annual Forward Capacity Market auction process described in Section III.13.2 of Market Rule 1.

Forward Capacity Auction Starting Price is calculated in accordance with Section III.13.2.4 of Market Rule 1.

Forward Capacity Market (FCM) is the forward market for procuring capacity in the New England Control Area, as described in Section III.13 of Market Rule 1.

Forward Energy Inventory Election is the total MWh value for which a Market Participant elects to be compensated at the forward rate in the inventoried energy program as described in Section III.K.1(d) of Market Rule 1.

Forward LNG Inventory Election is the portion of a Market Participant's Forward Energy Inventory Election attributed to liquefied natural gas in the inventoried energy program as described in Section III.K.1(d) of Market Rule 1.

Forward Reserve means TMNSR and TMOR purchased by the ISO on a forward basis on behalf of Market Participants as provided for in Section III.9 of Market Rule 1.

Forward Reserve Assigned Megawatts is the amount of Forward Reserve, in megawatts, that a Market Participant assigns to eligible Forward Reserve Resources to meet its Forward Reserve Obligation as defined in Section III.9.4.1 of Market Rule 1.

Forward Reserve Auction is the periodic auction conducted by the ISO in accordance with Section III.9 of Market Rule 1 to procure Forward Reserve.

Forward Reserve Auction Offers are offers to provide Forward Reserve to meet system and Reserve Zone requirements as submitted by a Market Participant in accordance with Section III.9.3 of Market Rule 1.

Forward Reserve Charge is a Market Participant's share of applicable system and Reserve Zone Forward Reserve costs attributable to meeting the Forward Reserve requirement as calculated in accordance with Section III.9.9 of Market Rule 1.

Forward Reserve Clearing Price is the clearing price for TMNSR or TMOR, as applicable, for the system and each Reserve Zone resulting from the Forward Reserve Auction as defined in Section III.9.4 of Market Rule 1.

Forward Reserve Credit is the credit received by a Market Participant that is associated with that Market Participant's Final Forward Reserve Obligation as calculated in accordance with Section III.9.8 of Market Rule 1.

Forward Reserve Delivered Megawatts are calculated in accordance with Section III.9.6.5 of Market Rule 1.

Forward Reserve Delivery Period is defined in Section III.9.1 of Market Rule 1.

Forward Reserve Failure-to-Activate Megawatts are calculated in accordance with Section III.9.7.2(a) of Market Rule 1.

Forward Reserve Failure-to-Activate Penalty is the penalty associated with a Market Participant's failure to activate Forward Reserve when requested to do so by the ISO and is defined in Section III.9.7.2 of Market Rule 1.

Forward Reserve Failure-to-Activate Penalty Rate is specified in Section III.9.7.2 of Market Rule 1.

Forward Reserve Failure-to-Reserve, as specified in Section III.9.7.1 of Market Rule 1, occurs when a Market Participant's Forward Reserve Delivered Megawatts for a Reserve Zone in an hour is less than that Market Participant's Forward Reserve Obligation for that Reserve Zone in that hour. Under these circumstances the Market Participant pays a penalty based upon the Forward Reserve Failure-to-Reserve Penalty Rate and that Market Participant's Forward Reserve Failure-to-Reserve Megawatts.

Forward Reserve Failure-to-Reserve Megawatts are calculated in accordance with Section III.9.7.1(a) of Market Rule 1.

Forward Reserve Failure-to-Reserve Penalty is the penalty associated with a Market Participant's failure to reserve Forward Reserve and is defined in Section III.9.7.1 of Market Rule 1.

Forward Reserve Failure-to-Reserve Penalty Rate is specified in Section III.9.7.1(b)(ii) of Market Rule 1.

Forward Reserve Fuel Index is the index or set of indices used to calculate the Forward Reserve Threshold Price as defined in Section III.9.6.2 of Market Rule 1.

Forward Reserve Heat Rate is the heat rate as defined in Section III.9.6.2 of Market Rule 1 that is used to calculate the Forward Reserve Threshold Price.

Forward Reserve Market is a market for forward procurement of two reserve products, Ten-Minute Non-Spinning Reserve (TMNSR) and Thirty-Minute Operating Reserve (TMOR).

Forward Reserve MWs are those megawatts assigned to specific eligible Forward Reserve Resources which convert a Forward Reserve Obligation into a Resource-specific obligation.

Forward Reserve Obligation is a Market Participant's amount, in megawatts, of Forward Reserve that cleared in the Forward Reserve Auction and adjusted, as applicable, to account for bilateral transactions that transfer Forward Reserve Obligations.

Forward Reserve Obligation Charge is defined in Section III.10.4 of Market Rule 1.

Forward Reserve Offer Cap is $9,000/megawatt-month.

Forward Reserve Payment Rate is defined in Section III.9.8 of Market Rule 1.

Forward Reserve Procurement Period is defined in Section III.9.1 of Market Rule 1.

Forward Reserve Qualifying Megawatts refer to all or a portion of a Forward Reserve Resource's capability offered into the Real-Time Energy Market at energy offer prices above the applicable Forward Reserve Threshold Price that are calculated in accordance with Section III.9.6.4 of Market Rule 1.

Forward Reserve Resource is a Resource that meets the eligibility requirements defined in Section III.9.5.2 of Market Rule 1 that has been assigned Forward Reserve Obligation by a Market Participant.

Forward Reserve Threshold Price is the minimum price at which assigned Forward Reserve Megawatts are required to be offered into the Real-Time Energy Market as calculated in Section III.9.6.2 of Market Rule 1.

FTR Auction is the periodic auction of FTRs conducted by the ISO in accordance with Section III.7 of Market Rule 1.

FTR Auction Revenue is the revenue collected from the sale of FTRs in FTR Auctions. FTR Auction Revenue is payable to FTR Holders who submit their FTRs for sale in the FTR Auction in accordance with Section III.7 of Market Rule 1 and to ARR Holders and Incremental ARR Holders in accordance with Appendix C of Market Rule 1.

FTR Credit Test Percentage is calculated in accordance with Section III.B.1(b) of the ISO New England Financial Assurance Policy.

FTR Financial Assurance Requirements are described in Section VI of the ISO New England Financial Assurance Policy.

FTR Holder is an entity that acquires an FTR through the FTR Auction to Section III.7 of Market Rule 1 and registers with the ISO as the holder of the FTR in accordance with Section III.7 of Market Rule 1 and applicable ISO New England Manuals.

FTR-Only Customer is a Market Participant that transacts in the FTR Auction and that does not participate in other markets or programs of the New England Markets. References in this Tariff to a "Non-Market Participant FTR Customers" and similar phrases shall be deemed references to an FTR-Only Customer.

FTR Settlement Risk Financial Assurance is an amount of financial assurance required by a Designated FTR Participant for each bid submission into an FTR Auction and for each bid awarded to the individual participant in an FTR Auction. This amount is calculated pursuant to Section VI.A of the ISO New England Financial Assurance Policy.

GADS Data means data submitted to the NERC for collection into the NERC's Generating Availability Data System (GADS).

Gap Request for Proposals (Gap RFP) is defined in Section III.11 of Market Rule 1.

Gas Day means a period of 24 consecutive hours beginning at 0900 hrs Central Time.

Generating Capacity Resource means a New Generating Capacity Resource or an Existing Generating Capacity Resource.

Generator Asset is a device (or a collection of devices) that is capable of injecting real power onto the grid that has been registered as a Generator Asset in accordance with the Asset Registration Process.

Generator Imbalance Service is the form of Ancillary Service described in Schedule 10 of the OATT.

Generator Interconnection Related Upgrade is an addition to or modification of the New England Transmission System (pursuant to Section II.47.1, Schedule 22 or Schedule 23 of the OATT) to effect the interconnection of a new generating unit or an existing generating unit whose energy capability or capacity capability is being materially changed and increased whether or not the interconnection is being effected to meet the Capacity Capability Interconnection Standard or the Network Capability Interconnection Standard. As to Category A Projects (as defined in Schedule 11 of the OATT), a Generator Interconnection Related Upgrade also includes an upgrade beyond that required to satisfy the Network Capability Interconnection Standard (or its predecessor) for which the Generator Owner has committed to pay prior to October 29, 1998.

Generator Owner is the owner, in whole or part, of a generating unit whether located within or outside the New England Control Area.

Good Utility Practice means any of the practices, methods and acts engaged in or approved by a significant portion of the electric utility industry during the relevant time period, or any of the practices, methods and acts which, in the exercise of reasonable judgment in light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety and expedition. Good Utility Practice is not intended to be limited to the optimum practice, method, or act to the exclusion of all others, but rather includes all acceptable practices, methods, or acts generally accepted in the region, including those practices required by Federal Power Act Section 215(a)(4).

Governance Only Member is defined in Section 1 of the Participants Agreement.

Governance Participant is defined in the Participants Agreement.

Governing Documents, for the purposes of the ISO New England Billing Policy, are the Transmission, Markets and Services Tariff and ISO Participants Agreement.

Governing Rating is the lowest corporate rating from any Rating Agency for that Market Participant, or, if the Market Participant has no corporate rating, then the lowest rating from any Rating Agency for that Market Participant’s senior unsecured debt.

Grandfathered Agreements (GAs) is a transaction specified in Section II.45 for the applicable period specified in that Section.

Grandfathered Intertie Agreement (GIA) is defined pursuant to the TOA.

Handy-Whitman Index of Public Utility Construction Costs is the Total Other Production Plant index shown in the Cost Trends of Electric Utility Construction for the North Atlantic Region as published in the Handy-Whitman Index of Public Utility Construction Costs.

Highgate Transmission Facilities (HTF) are existing U. S.-based transmission facilities covered under the Agreement for Joint Ownership, Construction and Operation of the Highgate Transmission Interconnection dated as of August 1, 1984 including (1) the whole of a 200 megawatt high-voltage, back-to-back, direct-current converter facility located in Highgate, Vermont and (2) a 345 kilovolt transmission line within Highgate and Franklin, Vermont (which connects the converter facility at the U.S.-Canadian border to a Hydro-Quebec 120 kilovolt line in Bedford, Quebec). The HTF include any upgrades associated with increasing the capacity or changing the physical characteristics of these facilities as defined in the above stated agreement dated August 1, 1984 until the Operations Date, as defined in the TOA. The current HTF rating is a nominal 225 MW. The HTF are not defined as PTF. Coincident with the Operations Date and except as stipulated in Schedules, 9, 12, and Attachment F to the OATT, HTF shall be treated in the same manner as PTF for purposes of the OATT and all references to PTF in the OATT shall be deemed to apply to HTF as well. The treatment of the HTF is not intended to establish any binding precedent or presumption with regard to the treatment for other transmission facilities within the New England Transmission System (including HVDC, MTF, or Control Area Interties) for purposes of the OATT.

Host Participant or Host Utility is a Market Participant or a Governance Participant transmission or distribution provider that reconciles the loads within the metering domain with OP-18 compliant metering.

Hourly Charges are defined in Section 1.3 of the ISO New England Billing Policy.

Hourly PER is calculated in accordance with Section III.13.7.1.2.1 of Market Rule 1.

Hourly Requirements are determined in accordance with Section III.A(i) of the ISO New England Financial Assurance Policy.

Hourly Shortfall NCPC Credit is an NCPC Credit calculated pursuant to Appendix F to Market Rule 1.

Hub is a specific set of pre-defined Nodes for which a Locational Marginal Price will be calculated for the Day-Ahead Energy Market and Real-Time Energy Market and which can be used to establish a reference price for energy purchases and the transfer of Day-Ahead Adjusted Load Obligations and Real-Time Adjusted Load Obligations and for the designation of FTRs.

Hub Price is calculated in accordance with Section III.2.8 of Market Rule 1.

HQ Interconnection Capability Credit (HQICC) is a monthly value reflective of the annual installed capacity benefits of the Phase I/II HVDC-TF, as determined by the ISO, using a standard methodology on file with the Commission, in conjunction with the setting of the Installed Capacity Requirement. An appropriate share of the HQICC shall be assigned to an IRH if the Phase I/II HVDC-TF support costs are paid by that IRH and such costs are not included in the calculation of the Regional Network Service rate. The share of HQICC allocated to such an eligible IRH for a month is the sum in kilowatts of (1)(a) the IRH's percentage share, if any, of the Phase I Transfer Capability times (b) the Phase I Transfer Credit, plus (2)(a) the IRH's percentage share, if any, of the Phase II Transfer Capability, times (b) the Phase II Transfer Credit. The ISO shall establish appropriate HQICCs to apply for an IRH which has such a percentage share.

Import Capacity Resource means an Existing Import Capacity Resource or a New Import Capacity Resource offered to provide capacity in the New England Control Area from an external Control Area.

Inadvertent Energy Revenue is defined in Section III.3.2.1(o) of Market Rule 1.

Inadvertent Energy Revenue Charges or Credits is defined in Section III.3.2.1(p) of Market Rule 1.

Inadvertent Interchange means the difference between net actual energy flow and net scheduled energy flow into or out of the New England Control Area.

Increment Offer means an offer to sell energy at a specified Location in the Day-Ahead Energy Market which is not associated with a physical supply. An accepted Increment Offer results in scheduled supply at the specified Location in the Day-Ahead Energy Market.

Incremental ARR is an ARR provided in recognition of a participant-funded transmission system upgrade pursuant to Appendix C of this Market Rule.

Incremental ARR Holder is an entity which is the record holder of an Incremental Auction Revenue Right in the register maintained by the ISO.

Incremental Cost of Reliability Service is described in Section III.13.2.5.2.5.2 of Market Rule 1.

Independent Transmission Company (ITC) is a transmission entity that assumes certain responsibilities in accordance with Section 10.05 of the Transmission Operating Agreement and Attachment M to the OATT, subject to the acceptance or approval of the Commission and a finding of the Commission that the transmission entity satisfies applicable independence requirements.

Information Request is a request from a potential Disputing Party submitted in writing to the ISO for access to Confidential Information.

Initial Market Participant Financial Assurance Requirement is calculated for new Market Participants and Returning Market Participants, other than an FTR-Only Customer or a Governance Only Member, according to Section IV of the ISO New England Financial Assurance Policy.

Installed Capacity Requirement means the level of capacity required to meet the reliability requirements defined for the New England Control Area, as described in Section III.12 of Market Rule 1.

Interchange Transactions are transactions deemed to be effected under Market Rule 1.

Interconnecting Transmission Owner has the meaning specified in Section I of Schedule 22, Attachment 1 to Schedule 23, and Section I of Schedule 25 of the OATT.

Interconnection Agreement is the "Large Generator Interconnection Agreement", the "Small Generator Interconnection Agreement", or the "Elective Transmission Upgrade Interconnection Agreement"

pursuant to Schedules 22, 23 or 25 of the ISO OATT or an interconnection agreement approved by the Commission prior to the adoption of the Interconnection Procedures.

Interconnection Customer has the meaning specified in Section I of Schedule 22, Attachment 1 to Schedule 23, and Section I of Schedule 25 of the OATT.

Interconnection Feasibility Study Agreement has the meaning specified in Section I of Schedule 22, Attachment 1 to Schedule 23, or Section I of Schedule 25 of the OATT.

Interconnection Procedure is the "Large Generator Interconnection Procedures", the "Small Generator Interconnection Procedures", or the "Elective Transmission Upgrade Interconnection Procedures" pursuant to Schedules 22, 23, and 25 of the ISO OATT.

Interconnection Reliability Operating Limit (IROL) has the meaning specified in the Glossary of Terms Used in NERC Reliability Standards.

Interconnection Request has the meaning specified in Section I of Schedule 22, Attachment 1 to Schedule 23, or Section I of Schedule 25 of the OATT.

Interconnection Rights Holder(s) (IRH) has the meaning given to it in Schedule 20A to Section II of this Tariff.

Interconnection System Impact Study Agreement has the meaning specified in Section I of Schedule 22, Attachment 1 to Schedule 23 and Section I of Schedule 25 of the OATT.

Interest is interest calculated in the manner specified in Section II.8.3.

Interface Bid is a unified real-time bid to simultaneously purchase and sell energy on each side of an external interface for which the enhanced scheduling procedures in Section III.1.10.7.A are implemented.

Intermittent Power Resource is a wind, solar, run of river hydro or other renewable resource that does not have control over its net power output.

Internal Bilateral for Load is an internal bilateral transaction under which the buyer receives a reduction in Real-Time Load Obligation and the seller receives a corresponding increase in Real-Time Load Obligation in the amount of the sale, in MWs. An Internal Bilateral for Load transaction is only applicable in the Real-Time Energy Market.

Internal Bilateral for Market for Energy is an internal bilateral transaction for Energy which applies in the Day-Ahead Energy Market and Real-Time Energy Market or just the Real-Time Energy Market under which the buyer receives a reduction in Day-Ahead Adjusted Load Obligation and Real-Time Adjusted Load Obligation and the seller receives a corresponding increase in Day-Ahead Adjusted Load Obligation and Real-Time Adjusted Load Obligation in the amount of the sale, in MWs.

Internal Elective Transmission Upgrade (Internal ETU) is defined in Section I of Schedule 25 of the OATT.

Internal Market Monitor means the department of the ISO responsible for carrying out the market monitoring and mitigation functions specified in Appendix A and elsewhere in Market Rule 1.

Interregional Planning Stakeholder Advisory Committee (IPSAC) is the committee described as such in the Northeast Planning Protocol.

Interregional Transmission Project is a transmission project located within the New England Control Area and one or more of the neighboring transmission planning regions.

Interruption Cost is the amount, in dollars, that must be paid to a Market Participant each time the Market Participant's Demand Response Resource is scheduled or dispatched in the New England Markets to reduce demand.

Inventoried Energy Day is an Operating Day that occurs in the months of December, January, or February during the winters of 2023-2024 ~~and 2024-2025~~ (inventoried energy program) and for which the average of the high temperature and the low temperature on that Operating Day, as measured and reported by the National Weather Service at Bradley International Airport in Windsor Locks, Connecticut, is less than or equal to 17 degrees Fahrenheit, as described in Section III.K.3.1 of Market Rule 1.

Investment Grade Rating, for a Market (other than an FTR-Only Customer) or Non-Market Participant Transmission Customer, is either (a) a corporate investment grade rating from one or more of the Rating Agencies, or (b) if the Market Participant or Non-Market Participant Transmission Customer does not have a corporate rating from one of the Rating Agencies, then an investment grade rating for the Market Participant's or Non-Market Participant Transmission Customer's senior unsecured debt from one or more of the Rating Agencies.

Invoice is a statement issued by the ISO for the net Charge owed by a Covered Entity pursuant to the ISO New England Billing Policy.

Invoice Date is the day on which the ISO issues an Invoice.

ISO means ISO New England Inc.

ISO Charges, for the purposes of the ISO New England Billing Policy, are both Non-Hourly Charges and Hourly Charges.

ISO Control Center is the primary control center established by the ISO for the exercise of its Operating Authority and the performance of functions as an RTO.

ISO-Initiated Claimed Capability Audit is the audit performed pursuant to Section III.1.5.1.4.

ISO New England Administrative Procedures means procedures adopted by the ISO to fulfill its responsibilities to apply and implement ISO New England System Rules.

ISO New England Billing Policy is Exhibit ID to Section I of the Transmission, Markets and Services Tariff.

ISO New England Filed Documents means the Transmission, Markets and Services Tariff, including but not limited to Market Rule 1, the Participants Agreement, the Transmission Operating Agreement or other documents that affect the rates, terms and conditions of service.

ISO New England Financial Assurance Policy is Exhibit IA to Section I of the Transmission, Markets and Services Tariff.

ISO New England Information Policy is the policy establishing guidelines regarding the information received, created and distributed by Market Participants and the ISO in connection with the settlement, operation and planning of the System, as the same may be amended from time to time in accordance with the provisions of this Tariff. The ISO New England Information Policy is Attachment D to the Transmission, Markets and Services Tariff.

ISO New England Manuals are the manuals implementing Market Rule 1, as amended from time to time in accordance with the Participants Agreement. Any elements of the ISO New England Manuals that substantially affect rates, terms, and/or conditions of service shall be filed with the Commission under Section 205 of the Federal Power Act.

ISO New England Operating Documents are the Tariff and the ISO New England Operating Procedures.

ISO New England Operating Procedures (OPs) are the ISO New England Planning Procedures and the operating guides, manuals, procedures and protocols developed and utilized by the ISO for operating the ISO bulk power system and the New England Markets.

ISO New England Planning Procedures are the procedures developed and utilized by the ISO for planning the ISO bulk power system.

ISO New England System Rules are Market Rule 1, the ISO New England Information Policy, the ISO New England Administrative Procedures, the ISO New England Manuals and any other system rules, procedures or criteria for the operation of the New England Transmission System and administration of the New England Markets and the Transmission, Markets and Services Tariff.

ITC Agreement is defined in Attachment M to the OATT.

ITC Rate Schedule is defined in Section 3.1 of Attachment M to the OATT.

ITC System is defined in Section 2.2 of Attachment M to the OATT.

ITC System Planning Procedures is defined in Section 15.4 of Attachment M to the OATT.

Joint ISO/RTO Planning Committee (JIPC) is the committee described as such in the Northeastern Planning Protocol.

Late Payment Account is a segregated interest-bearing account into which the ISO deposits Late Payment Charges due from ISO Charges and interest owed from participants for late payments that are collected and not distributed to the Covered Entities, until the Late Payment Account Limit is reached, under the ISO New England Billing Policy and penalties collected under the ISO New England Financial Assurance Policy.

Late Payment Account Limit is defined in Section 4.2 of the ISO New England Billing Policy.

Late Payment Charge is defined in Section 4.1 of the ISO New England Billing Policy.

Lead Market Participant, for purposes other than the Forward Capacity Market, is the entity authorized to submit Supply Offers, Demand Bids or Demand Reduction Offers for a Resource and to whom certain Energy TUs are assessed under Schedule 2 of Section IV.A of the Tariff. For purposes of the Forward Capacity Market, the Lead Market Participant is the entity designated to participate in that market on behalf of an Existing Capacity Resource or a New Capacity Resource.

Limited Energy Resource means a Generator Asset that, due to design considerations, environmental restriction on operations, cyclical requirements, such as the need to recharge or refill or manage water flow, or fuel limitations, are unable to operate continuously at full output on a daily basis.

Load Asset means a physical load that has been registered in accordance with the Asset Registration Process. A Load Asset can be an Asset Related Demand, including a Dispatchable Asset Related Demand.

Load Management means measures (e.g., products, equipment, systems, services, practices and/or strategies) on end-use customer facilities that curtail electrical usage or shift electrical usage while delivering a comparable or acceptable level of end-use service. Such measures include, but are not limited to, energy management systems, load control end-use cycling, load curtailment strategies, and energy storage that curtails or shifts electrical usage by means other than generating electricity.

Load Shedding is the systematic reduction of system demand by temporarily decreasing load.

Load Zone is a Reliability Region, except as otherwise provided for in Section III.2.7 of Market Rule 1.

Local Area Facilities are defined in the TOA**.**

Local Benefit Upgrade(s) (LBU) is an upgrade, modification or addition to the transmission system that is: (i) rated below 115kV or (ii) rated 115kV or above and does not meet all of the non-voltage criteria for PTF classification specified in the OATT.

Local Control Centers are those control centers in existence as of the effective date of the OATT (including the CONVEX, REMVEC, Maine and New Hampshire control centers) or established by the PTOs in accordance with the TOA that are separate from the ISO Control Center and perform certain functions in accordance with the OATT and the TOA.

Local Delivery Service is the service of delivering electric energy to end users. This service is subject to state jurisdiction regardless of whether such service is provided over local distribution or transmission facilities. An entity that is an Eligible Customer under the OATT is not excused from any requirements of state law, or any order or regulation issued pursuant to state law, to arrange for Local Delivery Service with the Participating Transmission Owner and/or distribution company providing such service and to pay all applicable charges associated with such service, including charges for stranded costs and benefits.

Local Network is defined as the transmission facilities constituting a local network as identified in Attachment E, as such Attachment may be modified from time to time in accordance with the Transmission Operating Agreement.

Local Network Load is the load that a Network Customer designates for Local Network Service under Schedule 21 to the OATT.

Local Network RNS Rate is the rate applicable to Regional Network Service to effect a delivery to load in a particular Local Network, as determined in accordance with Schedule 9 to the OATT.

Local Network Service (LNS) is the network service provided under Schedule 21 and the Local Service Schedules to permit the Transmission Customer to efficiently and economically utilize its resources to serve its load.

Local Point-To-Point Service (LPTP) is Point-to-Point Service provided under Schedule 21 of the OATT and the Local Service Schedules to permit deliveries to or from an interconnection point on the PTF.

Local Public Policy Transmission Upgrade is any addition and/or upgrade to the New England Transmission System with a voltage level below 115kV that is required in connection with the construction of a Public Policy Transmission Upgrade approved for inclusion in the Regional System Plan pursuant to Attachment K to the ISO OATT or included in a Local System Plan in accordance with Appendix 1 to Attachment K.

Local Resource Adequacy Requirement is calculated pursuant to Section III.12.2.1.1.

Local Second Contingency Protection Resources are those Resources identified by the ISO on a daily basis as necessary for the provision of Operating Reserve requirements and adherence to NERC, NPCC and ISO reliability criteria over and above those Resources required to meet first contingency reliability criteria within a Reliability Region.

Local Service is transmission service provided under Schedule 21 and the Local Service Schedules thereto.

Local Service Schedule is a PTO-specific schedule to the OATT setting forth the rates, charges, terms and conditions applicable to Local Service.

Local Sourcing Requirement (LSR) is a value calculated as described in Section III.12.2.1 of Market Rule 1.

Local System Planning (LSP) is the process defined in Appendix 1 of Attachment K to the OATT.

Localized Costs are costs that the ISO, with advisory input from the Reliability Committee, determines in accordance with Schedule 12C of the OATT shall not be included in the Pool-Supported PTF costs

recoverable under this OATT, or in costs allocated to Regional Network Load according to Section 6 of Schedule 12. If there are any Localized Costs, the ISO shall identify them in the Regional System Plan.

Location is a Node, External Node, Load Zone, DRR Aggregation Zone, or Hub.

Locational Marginal Price (LMP) is defined in Section III.2 of Market Rule 1. The Locational Marginal Price for a Node is the nodal price at that Node; the Locational Marginal Price for an External Node is the nodal price at that External Node; the Locational Marginal Price for a Load Zone, DRR Aggregation Zone or Reliability Region is the Zonal Price for that Load Zone, DRR Aggregation Zone or Reliability Region, respectively; and the Locational Marginal Price for a Hub is the Hub Price for that Hub.

Long Lead Time Facility (Long Lead Facility) has the meaning specified in Section I of Schedule 22 and Schedule 25 of the OATT.

Long-Term is a term of one year or more.

Long-Term Transmission Outage is a long-term transmission outage scheduled in accordance with ISO New England Operating Procedure No. 3.

Loss Component is the component of the nodal LMP at a given Node or External Node on the PTF that reflects the cost of losses at that Node or External Node relative to the reference point. The Loss Component of the nodal LMP at a given Node on the non-PTF system reflects the relative cost of losses at that Node adjusted as required to account for losses on the non-PTF system already accounted for through tariffs associated with the non-PTF. When used in connection with Hub Price or Zonal Price, the term Loss Component refers to the Loss Components of the nodal LMPs that comprise the Hub Price or Zonal Price, which Loss Components are averaged or weighted in the same way that nodal LMPs are averaged to determine Hub Price or weighted to determine Zonal Price.

Loss of Load Expectation (LOLE) is the probability of disconnecting non-interruptible customers due to a resource deficiency.

Lost Opportunity Cost (LOC) is one of four forms of compensation that may be paid to resources providing VAR Service under Schedule 2 of the OATT.

LSE means load serving entity.

Lump Sum Blackstart Payment is defined and calculated as specified in Section 5.4 of Schedule 16 to the OATT.

Lump Sum Blackstart Capital Payment is defined and calculated as specified in Section 5.4 of Schedule 16 to the OATT.

Manual Response Rate is the rate, in MW/Minute, at which the output of a Generator Asset, or the consumption of a Dispatchable Asset Related Demand, is capable of changing.

Marginal Loss Revenue Load Obligation is defined in Section III.3.2.1(b) of Market Rule 1.

Marginal Reliability Impact is the change, with respect to an increment of capacity supply, in expected unserved energy due to resource deficiency, as measured in hours per year.

Market Credit Limit is a credit limit for a Market Participant's Financial Assurance Obligations (except FTR Financial Assurance Requirements) established for each Market Participant in accordance with Section II.C of the ISO New England Financial Assurance Policy.

Market Credit Test Percentage is calculated in accordance with Section III.B.1(a) of the ISO New England Financial Assurance Policy.

Market Efficiency Transmission Upgrade is defined as those additions and upgrades that are not related to the interconnection of a generator, and, in the ISO's determination, are designed to reduce bulk power system costs to load system-wide, where the net present value of the reduction in bulk power system costs to load system-wide exceeds the net present value of the cost of the transmission addition or upgrade. For purposes of this definition, the term "bulk power system costs to load system-wide" includes, but is not limited to, the costs of energy, capacity, reserves, losses and impacts on bilateral prices for electricity.

Market Participant is a participant in the New England Markets (including a FTR-Only Customer) that has executed a Market Participant Service Agreement, or on whose behalf an unexecuted Market Participant Service Agreement has been filed with the Commission.

Market Participant Financial Assurance Requirement is defined in Section III of the ISO New England Financial Assurance Policy.

Market Participant Obligations is defined in Section III.B.1.1 of Appendix B of Market Rule 1.

Market Participant Service Agreement (MPSA) is an agreement between the ISO and a Market Participant, in the form specified in Attachment A or Attachment A-1 to the Tariff, as applicable.

Market Rule 1 is ISO Market Rule 1 and appendices set forth in Section III of this ISO New England Inc. Transmission, Markets and Services Tariff, as it may be amended from time to time.

Market Violation is a tariff violation, violation of a Commission-approved order, rule or regulation, market manipulation, or inappropriate dispatch that creates substantial concerns regarding unnecessary market inefficiencies.

Material Adverse Change is any change in financial status including, but not limited to a downgrade to below an Investment Grade Rating by any Rating Agency, being placed on credit watch with negative implication by any Rating Agency if the Market Participant or Non-Market Participant Transmission Customer does not have an Investment Grade Rating, a bankruptcy filing or other insolvency, a report of a significant quarterly loss or decline of earnings, the resignation of key officer(s), the sanctioning of the Market Participant or Non-Market Participant Transmission Customer or any of its Principles imposed by the Federal Energy Regulatory Commission, the Securities Exchange Commission, any exchange monitored by the National Futures Association, or any state entity responsible for regulating activity in energy markets; the filing of a material lawsuit that could materially adversely impact current or future financial results; a significant change in the Market Participant's or Non-Market Participant Transmission Customer's credit default spreads; or a significant change in market capitalization.

Material Adverse Impact is defined, for purposes of review of ITC-proposed plans, as a proposed facility or project will be deemed to cause a "material adverse impact" on facilities outside of the ITC System if: (i) the proposed facility or project causes non-ITC facilities to exceed their capabilities or

exceed their thermal, voltage or stability limits, consistent with all applicable reliability criteria, or (ii) the proposed facility or project would not satisfy the standards set forth in Section I.3.9 of the Transmission, Markets and Services Tariff. This standard is intended to assure the continued service of all non-ITC firm load customers and the ability of the non-ITC systems to meet outstanding transmission service obligations.

Maximum Capacity Limit is a value calculated as described in Section III.12.2.2 of Market Rule 1.

Maximum Consumption Limit is the maximum amount, in MW, available for economic dispatch from a DARD and is based on the physical characteristics as submitted as part of the DARD's Offer Data. A Market Participant must maintain an up-to-date Maximum Consumption Limit (and where applicable, must provide the ISO with any telemetry required by ISO New England Operating Procedure No. 18 to allow the ISO to maintain an updated Maximum Consumption Limit) for all hours in which a DARD has been offered into the Day-Ahead Energy Market or Real-Time Energy Market.

Maximum Daily Energy Limit is the maximum amount of megawatt-hours that a Limited Energy Resource expects to be able to generate in the next Operating Day.

Maximum Daily Consumption Limit is the maximum amount of megawatt-hours that a Storage DARD expects to be able to consume in the next Operating Day.

Maximum Facility Load is the highest demand of an end-use customer facility since the start of the prior calendar year (or, if unavailable, an estimate thereof), where the demand evaluated is established by adding metered demand measured at the Retail Delivery Point and the output of all generators located behind the Retail Delivery Point in the same time intervals.

Maximum Interruptible Capacity is an estimate of the maximum demand reduction and Net Supply that a Demand Response Asset can deliver, as measured at the Retail Delivery Point.

Maximum Load is the highest demand since the start of the prior calendar year (or, if unavailable, an estimate thereof), as measured at the Retail Delivery Point.

Maximum Number of Daily Starts is the maximum number of times that a Binary Storage DARD or a Generator Asset can be started or that a Demand Response Resource can be interrupted in the next Operating Day under normal operating conditions.

Maximum Reduction is the maximum available demand reduction, in MW, of a Demand Response Resource that a Market Participant offers to deliver in the Day-Ahead Energy Market or Real-Time Energy Market, as reflected in the Demand Response Resource's Demand Reduction Offer.

Measure Life is the estimated time an On-Peak Demand Resource or Seasonal Peak Demand Resource measure will remain in place, or the estimated time period over which the facility, structure, equipment or system in which a measure is installed continues to exist, whichever is shorter. Suppliers of On-Peak Demand Resources or Seasonal Peak Demand Resources comprised of an aggregation of measures with varied Measures Lives shall determine and document the Measure Life either: (i) for each type of measure with a different Measure Life and adjust the aggregate performance based on the individual measure life calculation in the portfolio; or (ii) as the average Measure Life for the aggregated measures as long as the demand reduction capability of the resource is greater than or equal to the amount that cleared in the Forward Capacity Auction or reconfiguration auction for the entire Capacity Commitment Period, and the demand reduction capability for an Existing On-Peak Demand Resource or Existing Seasonal Peak Demand Resource is not over-stated in a subsequent Capacity Commitment Period. Measure Life shall be determined consistent with the resource's Measurement and Verification Plan, which shall be reviewed by the ISO to ensure consistency with the measurement and verification requirements of Market Rule 1 and the ISO New England Manuals.

Measurement and Verification Documents mean the measurement and verification documents described in Section 13.1.4.3.1 of Market Rule 1 that are submitted by On-Peak Demand Resources and Seasonal Peak Demand Resources, which include Measurement and Verification Plans, Updated Measurement and Verification Plans, Measurement and Verification Summary Reports, and Measurement and Verification Reference Reports.

Measurement and Verification Plan means the measurement and verification plan submitted by an On-Peak Demand Resource or Seasonal Peak Demand Resource as part of the qualification process for the Forward Capacity Auction pursuant to the requirements of Section III.13.1.4.3 of Market Rule 1 and the ISO New England Manuals.

Measurement and Verification Reference Reports are optional reports submitted by On-Peak Demand Resources or Seasonal Peak Demand Resources during the Capacity Commitment Period subject to the schedule in the Measurement and Verification Plan and consistent with the schedule and reporting standards set forth in the ISO New England Manuals. Measurement and Verification Reference Reports update the prospective demand reduction capability of the On-Peak Demand Resource or Seasonal Peak Demand Resource project based on measurement and verification studies performed during the Capacity Commitment Period.

Measurement and Verification Summary Report is the monthly report submitted by an On-Peak Demand Resource or Seasonal Peak Demand Resource with the monthly settlement report for the Forward Capacity Market, which documents the total demand reduction capability for all On-Peak Demand Resources and Seasonal Peak Demand Resources in operation as of the end of the previous month.

MEPCO Grandfathered Transmission Service Agreement (MGTSA) is a MEPCO long-term firm point-to-point transmission service agreement with a POR or POD at the New Brunswick border and a start date prior to June 1, 2007 where the holder has elected, by written notice delivered to MEPCO within five (5) days following the filing of the settlement agreement in Docket Nos. ER07-1289 and EL08-56 or by September 1, 2008 (whichever is later), MGTSA treatment as further described in Section II.45.1.

Merchant Transmission Facilities (MTF) are the transmission facilities owned by MTOs, defined and classified as MTF pursuant to Schedule 18 of the OATT, over which the ISO shall exercise Operating Authority in accordance with the terms set forth in a MTOA or Attachment K to the OATT, rated 69 kV or above and required to allow energy from significant power sources to move freely on the New England Transmission System.

Merchant Transmission Facilities Provider (MTF Provider) is an entity as defined in Schedule 18 of the OATT.

Merchant Transmission Facilities Service (MTF Service) is transmission service over MTF as provided for in Schedule 18 of the OATT.

Merchant Transmission Operating Agreement (MTOA) is an agreement between the ISO and an MTO with respect to its MTF.

Merchant Transmission Owner (MTO) is an owner of MTF.

Meter Data Error means an error in meter data, including an error in Coincident Peak Contribution values, on an Invoice issued by the ISO after the completion of the Data Reconciliation Process as described in the ISO New England Manuals and in Section III.3.8 of Market Rule 1.

Meter Data Error RBA Submission Limit means the date thirty 30 calendar days after the issuance of the Invoice containing the results of the Data Reconciliation Process as described in the ISO New England Manuals and in Section III.3.6 of Market Rule 1.

Metered Quantity For Settlement is defined in Section III.3.2.1.1 of Market Rule 1.

Minimum Consumption Limit is (a) the lowest consumption level, in MW, available for economic dispatch from a DARD and is based on the physical characteristics as submitted as part of the DARD's Offer Data, and (b) for a DARD undergoing Facility and Equipment Testing or auditing, the level to which the DARD requests and is approved to operate or is directed to operate for purposes of completing the Facility and Equipment Testing or auditing.

Minimum Down Time is the number of hours that must elapse after a Generator Asset or Storage DARD has been released for shutdown at or below its Economic Minimum Limit or Minimum Consumption Limit before the Generator Asset or Storage DARD can be brought online and be released for dispatch at its Economic Minimum Limit or Minimum Consumption Limit.

Minimum Generation Emergency means an Emergency declared by the ISO in which the ISO anticipates requesting one or more Generator Assets to operate at or below Economic Minimum Limit in order to manage, alleviate, or end the Emergency.

Minimum Generation Emergency Credits are those Real-Time Dispatch NCPC Credits calculated pursuant to Appendix F of Market Rule 1 for resources within a reliability region that are dispatched during a period for which a Minimum Generation Emergency has been declared.

Minimum Reduction is the minimum available demand reduction, in MW, of a Demand Response Resource that a Market Participant offers to deliver in the Day-Ahead Energy Market or Real-Time Energy Market, as reflected in the Demand Response Resource's Demand Reduction Offer.

Minimum Reduction Time is the minimum number of hours of demand reduction at or above the Minimum Reduction for which the ISO must dispatch a Demand Response Resource to reduce demand.

Minimum Run Time is the number of hours that a Generator Asset must remain online after it has been scheduled to reach its Economic Minimum Limit before it can be released for shutdown from its Economic Minimum Limit or the number of hours that must elapse after a Storage DARD has been scheduled to consume at its Minimum Consumption Limit before it can be released for shutdown.

Minimum Time Between Reductions is the number of hours that must elapse after a Demand Response Resource has received a Dispatch Instruction to stop reducing demand before the Demand Response Resource can achieve its Minimum Reduction after receiving a Dispatch Instruction to start reducing demand.

Minimum Total Reserve Requirement, which does not include Replacement Reserve, is the combined amount of TMSR, TMNSR, and TMOR required system-wide as described in Section III.2.7A and ISO New England Operating Procedure No. 8.

Monthly Blackstart Service Charge is the charge made to Transmission Customers pursuant to Section 6 of Schedule 16 to the OATT.

Monthly Capacity Payment is the Forward Capacity Market payment described in Section III.13.7.3 of Market Rule 1.

Monthly Peak is defined in Section II.21.2 of the OATT.

Monthly PER is calculated in accordance with Section III.13.7.1.2.2 of Market Rule 1.

Monthly Real-Time Demand Reduction Obligation is the absolute value of a Customer's hourly Real-Time Demand Reduction Obligation summed for all hours in a month, in MWhs.

Monthly Real-Time Generation Obligation is the sum, for all hours in a month, at all Locations, of a Customer's Real-Time Generation Obligation, in MWhs.

Monthly Real-Time Load Obligation is the absolute value of a Customer's hourly Real-Time Load Obligation summed for all hours in a month, in MWhs.

Monthly Regional Network Load is defined in Section II.21.2 of the OATT.

Monthly Statement is the first weekly Statement issued on a Monday after the tenth of a calendar month that includes both the Hourly Charges for the relevant billing period and Non-Hourly Charges for the immediately preceding calendar month.

MRI Transition Period is the period specified in Section III.13.2.2.1.

MUI is the market user interface.

Municipal Market Participant is defined in Section II of the ISO New England Financial Assurance Policy.

MW is megawatt.

MWh is megawatt-hour.

Native Load Customers are the wholesale and retail power customers of a Transmission Owner on whose behalf the Transmission Owner, by statute, franchise, regulatory requirement, or contract, has undertaken an obligation to construct and operate its system to meet the reliable electric needs of such customers.

NCPC Charge means the charges to Market Participants calculated pursuant to Appendix F to Market Rule 1.

NCPC Credit means the credits to Market Participants calculated pursuant to Appendix F to Market Rule 1.

Needs Assessment is defined in Section 4.1 of Attachment K to the OATT.

NEMA, for purposes of Section III of the Tariff, is the Northeast Massachusetts Reliability Region.

NEMA Contract is a contract described in Appendix C of Market Rule 1 and listed in Exhibit 1 of Appendix C of Market Rule 1.

NEMA Load Serving Entity (NEMA LSE) is a Transmission Customer or Congestion Paying LSE Entity that serves load within NEMA.

NEMA or Northeast Massachusetts Upgrade, for purposes of Section II of the Tariff, is an addition to or modification of the PTF into or within the Northeast Massachusetts Reliability Region that was not, as of December 31, 1999, the subject of a System Impact Study or application filed pursuant to Section I.3.9 of the Transmission, Markets and Services Tariff; that is not related to generation interconnections; and that will be completed and placed in service by June 30, 2004. Such upgrades include, but are not limited to, new transmission facilities and related equipment and/or modifications to existing transmission facilities and related equipment. The list of NEMA Upgrades is contained in Schedule 12A of the OATT.

NEPOOL is the New England Power Pool, and the entities that collectively participated in the New England Power Pool.

NEPOOL Agreement is the agreement among the participants in NEPOOL.

NEPOOL GIS is the generation information system.

NEPOOL GIS Administrator is the entity or entities that develop, administer, operate and maintain the NEPOOL GIS.

NEPOOL GIS API Fees are the one-time on-boarding fees and annual maintenance fees charged to NEPOOL by the NEPOOL GIS Administrator for each NEPOOL Participant or Market Participant that accesses the NEPOOL GIS through an application programming interface pursuant to Rule 3.9(b) of the operating rules of the NEPOOL GIS.

NEPOOL Participant is a party to the NEPOOL Agreement.

NERC is the North American Electric Reliability Corporation or its successor organization.

NESCOE is the New England States Committee on Electricity, recognized by the Commission as the regional state committee for the New England Control Area.

Net Commitment Period Compensation (NCPC) is the compensation methodology for Resources that is described in Appendix F to Market Rule 1.

Net CONE is an estimate of the Cost of New Entry, net of the first-year non-capacity market revenues, for a reference technology resource type and is intended to equal the amount of capacity revenue the reference technology resource would require, in its first year of operation, to be economically viable given reasonable expectations of the first year energy and ancillary services revenues, and projected revenue for subsequent years.

Net Regional Clearing Price is described in Section III.13.7.5 of Market Rule 1.

Net Supply is energy injected into the transmission or distribution system at a Retail Delivery Point.

Net Supply Capability is the maximum Net Supply a facility is physically and contractually able to inject into the transmission or distribution system at its Retail Delivery Point.

Network Capability Interconnection Standard has the meaning specified in Section I of Schedule 22, Attachment 1 to Schedule 23, and Section I of Schedule 25 of the OATT.

Network Customer is a Transmission Customer receiving RNS or LNS.

Network Import Capability (NI Capability) is defined in Section I of Schedule 25 of the OATT.

Network Import Interconnection Service (NI Interconnection Service) is defined in Section I of Schedule 25 of the OATT.

Network Resource is defined as follows: (1) With respect to Market Participants, (a) any generating resource located in the New England Control Area which has been placed in service prior to the

Compliance Effective Date (including a unit that has lost its capacity value when its capacity value is restored and a deactivated unit which may be reactivated without satisfying the requirements of Section II.46 of the OATT in accordance with the provisions thereof) until retired; (b) any generating resource located in the New England Control Area which is placed in service after the Compliance Effective Date until retired, provided that (i) the Generator Owner has complied with the requirements of Sections II.46 and II.47 and Schedules 22 and 23 of the OATT, and (ii) the output of the unit shall be limited in accordance with Sections II.46 and II.47 and Schedules 22 and 23, if required; and (c) any generating resource or combination of resources (including bilateral purchases) located outside the New England Control Area for so long as any Market Participant has an Ownership Share in the resource or resources which is being delivered to it in the New England Control Area to serve Regional Network Load located in the New England Control Area or other designated Regional Network Loads contemplated by Section II.18.3 of the OATT taking Regional Network Service. (2) With respect to Non-Market Participant Transmission Customers, any generating resource owned, purchased or leased by the Non-Market Participant Transmission Customer which it designates to serve Regional Network Load.

New Brunswick Security Energy is defined in Section III.3.2.6A of Market Rule 1.

New Capacity Offer is an offer in the Forward Capacity Auction to provide capacity from a New Generating Capacity Resource, New Import Capacity Resource or New Demand Capacity Resource.

New Capacity Qualification Deadline is a deadline, specified in Section III.13.1.10 of Market Rule 1, for submission of certain qualification materials for the Forward Capacity Auction, as discussed in Section III.13.1 of Market Rule 1.

New Capacity Qualification Package is information submitted by certain new resources prior to participation in the Forward Capacity Auction, as described in Section III.13.1 of Market Rule 1.

New Capacity Resource is a resource (i) that never previously received any payment as a capacity resource including any capacity payment pursuant to the market rules in effect prior to June 1, 2010 and that has not cleared in any previous Forward Capacity Auction; or (ii) that is otherwise eligible to participate in the Forward Capacity Auction as a New Capacity Resource.

New Capacity Show of Interest Form is described in Section III.13.1.1.2.1 of Market Rule 1.

New Capacity Show of Interest Submission Window is the period of time during which a Project Sponsor may submit a New Capacity Show of Interest Form or a New Demand Capacity Resource Show of Interest Form, as described in Section III.13.1.10 of Market Rule 1.

New Demand Capacity Resource is a type of Demand Capacity Resource participating in the Forward Capacity Market, as defined in Section III.13.1.4.1 of Market Rule 1.

New Demand Capacity Resource Qualification Package is the information that a Project Sponsor must submit, in accordance with Section III.13.1.4.1.1.2 of Market Rule 1, for each resource that it seeks to offer in the Forward Capacity Auction as a New Demand Capacity Resource.

New Demand Capacity Resource Show of Interest Form is described in Section III.13.1.4.1.1.1 of Market Rule 1.

New England Control Area is the Control Area for New England, which includes PTF, Non-PTF, MTF and OTF. The New England Control Area covers Connecticut, Rhode Island, Massachusetts, New Hampshire, Vermont, and part of Maine (i.e., excluding the portions of Northern Maine and the northern portion of Eastern Maine which are in the Maritimes Control Area).

New England Markets are markets or programs for the purchase of energy, capacity, ancillary services, demand response services or other related products or services (including Financial Transmission Rights) that are delivered through or useful to the operation of the New England Transmission System and that are administered by the ISO pursuant to rules, rates, or agreements on file from time to time with the Federal Energy Regulatory Commission.

New England System Restoration Plan is the plan that is developed by ISO, in accordance with NERC Reliability Standards, NPCC regional criteria and standards, ISO New England Operating Documents and ISO operating agreements, to facilitate the restoration of the New England Transmission System following a partial or complete shutdown of the New England Transmission System.

New England Transmission System is the system of transmission facilities, including PTF, Non-PTF, OTF and MTF, within the New England Control Area under the ISO’s operational jurisdiction.

New Generating Capacity Resource is a type of resource participating in the Forward Capacity Market, as described in Section III.13.1.1.1 of Market Rule 1.

New Import Capacity Resource is a type of resource participating in the Forward Capacity Market, as defined in Section III.13.1.3.4 of Market Rule 1.

New Resource Offer Floor Price is defined in Section III.A.21.2.

NMPTC means Non-Market Participant Transmission Customer.

NMPTC Credit Threshold is described in Section V.A.2 of the ISO New England Financial Assurance Policy.

NMPTC Financial Assurance Requirement is an amount of additional financial assurance for Non-Market Participant Transmission Customers described in Section V.D of the ISO New England Financial Assurance Policy.

Node is a point on the New England Transmission System at which LMPs are calculated.

No-Load Fee is the amount, in dollars per hour, for a Generator Asset that must be paid to Market Participants with an Ownership Share in the Generator Asset for being scheduled in the New England Markets, in addition to the Start-Up Fee and price offered to supply energy, for each hour that the Generator Asset is scheduled in the New England Markets.

Nominated Consumption Limit is the consumption level specified by the Market Participant for a Dispatchable Asset Related Demand as adjusted in accordance with the provisions of Section III.13.7.5.1.3.

Non-Commercial Capacity is the capacity of a New Capacity Resource or an Existing Capacity Resource, or portion thereof, that has not achieved FCM Commercial Operation.

Non-Commercial Capacity Cure Period is the time period described in Section VII.D of the ISO New England Financial Assurance Policy.

Non-Commercial Capacity Financial Assurance Amount (Non-Commercial Capacity FA Amount) is the financial assurance amount held on Non-Commercial Capacity cleared in a Forward Capacity Auction as calculated in accordance with Section VII.B.2 of the ISO New England Financial Assurance Policy.

Non-Designated Blackstart Resource Study Cost Payments are the study costs reimbursed under Section 5.3 of Schedule 16 of the OATT.

Non-Dispatchable Resource is any Resource that does not meet the requirements to be a Dispatchable Resource.

Non-Hourly Charges are defined in Section 1.3 of the ISO New England Billing Policy.

Non-Hourly Requirements are determined in accordance with Section III.A(ii) of the ISO New England Financial Assurance Policy, which is Exhibit 1A of Section I of the Tariff.

Non-Incumbent Transmission Developer is a Qualified Transmission Project Sponsor that: (i) is not currently a PTO; (ii) has a transmission project listed in the RSP Project List; and (iii) has executed a Non-Incumbent Transmission Developer Operating Agreement. "Non-Incumbent Transmission Developer" also includes a PTO that proposes the development of a transmission facility not located within or connected to its existing electric system; however, because such a PTO is a party to the TOA, it is not required to enter into a Non-Incumbent Transmission Developer Operating Agreement.

Non-Incumbent Transmission Developer Operating Agreement (or NTDOA) is an agreement between the ISO and a Non-Incumbent Transmission Developer in the form specified in Attachment O to the OATT that sets forth their respective rights and responsibilities to each other with regard to proposals for and construction of certain transmission facilities.

Non-Market Participant is any entity that is not a Market Participant.

Non-Market Participant Transmission Customer is any entity which is not a Market Participant but is a Transmission Customer.

Non-Municipal Market Participant is defined in Section II of the ISO New England Financial Assurance Policy.

Non-PTF Transmission Facilities (Non-PTF) are the transmission facilities owned by the PTOs that do not constitute PTF, OTF or MTF.

Non-Qualifying means a Market Participant that is not a Credit Qualifying Market Participant.

Notice of RBA is defined in Section 6.3.2 of the ISO New England Billing Policy.

Notification Time is the time required for a Generator Asset to synchronize to the system from the time a startup Dispatch Instruction is received from the ISO.

Northeastern Planning Protocol is the Amended and Restated Northeastern ISO/RTO Planning Coordination Protocol on file with the Commission and posted on the ISO website at the following URL: www.iso-ne.com/static-assets/documents/2015/07/northeastern_protocol_dmeast.doc.

NPCC is the Northeast Power Coordinating Council.

Obligation Month means a time period of one calendar month for which capacity payments are issued and the costs associated with capacity payments are allocated.

Offer Data means the scheduling, operations planning, dispatch, new Resource, and other data, including Generator Asset, Dispatchable Asset Related Demand, and Demand Response Resource operating limits based on physical characteristics, and information necessary to schedule and dispatch Generator Assets, Dispatchable Asset Related Demands, and Demand Response Resources for the provision or consumption of energy, the provision of other services, and the maintenance of the reliability and security of the transmission system in the New England Control Area, and specified for submission to the New England Markets for such purposes by the ISO.

Offered CLAIM10 is a Supply Offer value or a Demand Reduction Offer value between 0 and the CLAIM10 of the resource that represents the amount of TMNSR available either from an off-line Fast Start Generator or from a Fast Start Demand Response Resource that has not been dispatched.

Offered CLAIM30 is a Supply Offer value or a Demand Reduction Offer value between 0 and the CLAIM30 of the resource that represents the amount of TMOR available either from an off-line Fast Start Generator or from a Fast Start Demand Response Resource that has not been dispatched.

On-Peak Demand Resource is a type of Demand Capacity Resource and means installed measures (e.g., products, equipment, systems, services, practices and/or strategies) on end-use customer facilities that reduce the total amount of electrical energy consumed during Demand Resource On-Peak Hours, while delivering a comparable or acceptable level of end-use service. Such measures include Energy Efficiency, Load Management, and Distributed Generation.

Open Access Same-Time Information System (OASIS) is the ISO information system and standards of conduct responding to requirements of 18 C.F.R. §37 of the Commission's regulations and all additional requirements implemented by subsequent Commission orders dealing with OASIS.

Open Access Transmission Tariff (OATT) is Section II of the ISO New England Inc. Transmission, Markets and Services Tariff.

Operating Authority is defined pursuant to a MTOA, an OTOA, the TOA or the OATT, as applicable.

Operating Data means GADS Data, data equivalent to GADS Data, CARL Data, metered load data, or actual system failure occurrences data, all as described in the ISO New England Operating Procedures.

Operating Day means the calendar day period beginning at midnight for which transactions on the New England Markets are scheduled.

Operating Reserve means Ten-Minute Spinning Reserve (TMSR), Ten-Minute Non-Spinning Reserve (TMNSR) and Thirty-Minute Operating Reserve (TMOR).

Operations Date is February 1, 2005.

OTF Service is transmission service over OTF as provided for in Schedule 20.

Other Transmission Facility (OTF) are the transmission facilities owned by Transmission Owners, defined and classified as OTF pursuant to Schedule 20, over which the ISO shall exercise Operating

Authority in accordance with the terms set forth in the OTOA, rated 69 kV or above, and required to allow energy from significant power sources to move freely on the New England Transmission System. OTF classification shall be limited to the Phase I/II HVDC-TF.

Other Transmission Operating Agreements (OTOA) is the agreement(s) between the ISO, an OTO and/or the associated service provider(s) with respect to an OTF, which includes the HVDC Transmission Operating Agreement and the Phase I/II HVDC-TF Transmission Service Administration Agreement. With respect to the Phase I/II HVDC-TF, the HVDC Transmission Operating Agreement covers the rights and responsibilities for the operation of the facility and the Phase I/II HVDC-TF Transmission Service Administration Agreement covers the rights and responsibilities for the administration of transmission service.

Other Transmission Owner (OTO) is an owner of OTF.

Ownership Share is a right or obligation, for purposes of settlement, to a percentage share of all credits or charges associated with a Generator Asset or a Load Asset, where such facility is interconnected to the New England Transmission System.

Participant Expenses are defined in Section 1 of the Participants Agreement.

Participant Required Balance is defined in Section 5.3 of the ISO New England Billing Policy.

Participant Vote is defined in Section 1 of the Participants Agreement.

Participants Agreement is the agreement among the ISO, the New England Power Pool and Individual Participants, as amended from time to time, on file with the Commission.

Participants Committee is the principal committee referred to in the Participants Agreement.

Participating Transmission Owner (PTO) is a transmission owner that is a party to the TOA.

Passive DR Audit is the audit performed pursuant to Section III.13.6.1.5.4.

Passive DR Auditing Period is the summer Passive DR Auditing Period (June 1 to August 31) or winter Passive DR Auditing Period (December 1 to January 31) applicable to On-Peak Demand Resources and Seasonal Peak Demand Resources.

Payment is a sum of money due to a Covered Entity from the ISO.

Payment Default Shortfall Fund is defined in Section 5.1 of the ISO New England Billing Policy.

Peak Energy Rent (PER) is described in Section III.13.7.1.2 of Market Rule 1.

PER Proxy Unit is described in Section III.13.7.1.2.1 of Market Rule 1.

Permanent De-list Bid is a bid that may be submitted by an Existing Generating Capacity Resource, Existing Import Capacity Resource, or Existing Demand Capacity Resource in the Forward Capacity Auction to permanently remove itself from the capacity market, as described in Section III.13.1.2.3.1.5 of Market Rule 1.

Phase I Transfer Credit is 40% of the HQICC, or such other fraction of the HQICC as the ISO may establish.

Phase I/II HVDC-TF is defined in Schedule 20A to Section II of this Tariff.

Phase I/II HVDC-TF Transfer Capability is the transfer capacity of the Phase I/II HVDC-TF under normal operating conditions, as determined in accordance with Good Utility Practice. The "Phase I Transfer Capability" is the transfer capacity under normal operating conditions, as determined in accordance with Good Utility Practice, of the Phase I terminal facilities as determined initially as of the time immediately prior to Phase II of the Phase I/II HVDC-TF first being placed in service, and as adjusted thereafter only to take into account changes in the transfer capacity which are independent of any effect of Phase II on the operation of Phase I. The "Phase II Transfer Capability" is the difference between the Phase I/II HVDC-TF Transfer Capability and the Phase I Transfer Capability. Determinations of, and any adjustment in, Phase I/II HVDC-TF Transfer Capability shall be made by the ISO, and the basis for any such adjustment shall be explained in writing and posted on the ISO website.

Phase One Proposal is a first round submission, as defined in Section 4.3 of Attachment K of the OATT, of a proposal for a Reliability Transmission Upgrade or Market Efficiency Transmission Upgrade, as applicable, by a Qualified Transmission Project Sponsor.

Phase II Transfer Credit is 60% of the HQICC, or such other fraction of the HQICC as the ISO may establish.

Phase Two Solution is a second round submission, as defined in Section 4.3 of Attachment K of the OATT, of a proposal for a Reliability Transmission Upgrade or Market Efficiency Transmission Upgrade by a Qualified Transmission Project Sponsor.

Planning Advisory Committee is the committee described in Attachment K of the OATT.

Planning and Reliability Criteria is defined in Section 3.3 of Attachment K to the OATT.

Planning Authority is an entity defined as such by the North American Electric Reliability Corporation.

Point(s) of Delivery (POD) is point(s) of interconnection where capacity and/or energy transmitted by a Transmission Customer will be made available to the Receiving Party under the OATT.

Point of Interconnection shall have the same meaning as that used for purposes of Schedules 22, 23 and 25 of the OATT.

Point(s) of Receipt (POR) is point(s) of interconnection where capacity and/or energy transmitted by a Transmission Customer will be made available by the Delivering Party under the OATT.

Point-To-Point Service is the transmission of capacity and/or energy on either a firm or non-firm basis from the Point(s) of Receipt to the Point(s) of Delivery under the OATT pursuant to Local Point-To-Point Service or OTF Service or MTF Service; and the transmission of capacity and/or energy from the Point(s) of Receipt to the Point(s) of Delivery under the OATT pursuant to Through or Out Service.

Pool-Planned Unit is one of the following units: New Haven Harbor Unit 1 (Coke Works), Mystic Unit 7, Canal Unit 2, Potter Unit 2, Wyman Unit 4, Stony Brook Units 1, 1A, 1B, 1C, 2A and 2B, Millstone

Unit 3, Seabrook Unit 1 and Waters River Unit 2 (to the extent of 7 megawatts of its Summer capability and 12 megawatts of its Winter capability).

Pool PTF Rate is the transmission rate determined in accordance with Schedule 8 to the OATT.

Pool RNS Rate is the transmission rate determined in accordance with paragraph (2) of Schedule 9 of Section II of the Tariff.

Pool-Scheduled Resources are described in Section III.1.10.2 of Market Rule 1.

Pool Supported PTF is defined as: (i) PTF first placed in service prior to January 1, 2000; (ii) Generator Interconnection Related Upgrades with respect to Category A and B projects (as defined in Schedule 11), but only to the extent not paid for by the interconnecting Generator Owner; and (iii) other PTF upgrades, but only to the extent the costs therefore are determined to be Pool Supported PTF in accordance with Schedule 12.

Pool Transmission Facility (PTF) means the transmission facilities owned by PTOs which meet the criteria specified in Section II.49 of the OATT.

Posting Entity is any Market Participant or Non-Market Participant Transmission Customer providing financial security under the provisions of the ISO New England Financial Assurance Policy.

Posture means an action of the ISO to deviate from the jointly optimized security constrained economic dispatch for Energy and Operating Reserves solution for a Resource produced by the ISO's technical software for the purpose of maintaining sufficient Operating Reserve (both online and off-line) or for the provision of voltage or VAR support.

Posturing Credits are the Real-Time Posturing NCPC Credits for Generators (Other Than Limited Energy Resources) Postured for Reliability and the Real-Time Posturing NCPC Credit for Limited Energy Resources Postured for Reliability.

Power Purchaser is the entity that is purchasing the capacity and/or energy to be transmitted under the OATT.

Principal is (i) the sole proprietor of a sole proprietorship; (ii) a general partner of a partnership; (iii) a president, chief executive officer, chief operating officer or chief financial officer (or equivalent position) of an organization; (iv) a manager, managing member or a member vested with the management authority for a limited liability company or limited liability partnership; (v) any person or entity that has the power to exercise a controlling influence over an organization's activities that are subject to regulation by the Federal Energy Regulatory Commission, the Securities and Exchange Commission, the Commodity Futures Trading Commission, any exchange monitored by the National Futures Association, or any state entity responsible for regulating activity in energy markets; or (vi) any person or entity that: (a) is the direct owner of 10% or more of any class of an organization's equity securities; or (b) has directly contributed 10% or more of an organization's capital.

Profiled Load Assets include all Load Assets that are not directly metered by OP-18 compliant metering as currently described in Section IV (Metering and Recording for Settlements) of OP18, and some Load Assets that are measured by OP-18 compliant metering (as currently described in Section IV of OP-18) to which the Host Participant Assigned Meter Reader allocates non-PTF losses.

Project Sponsor is an entity seeking to have a New Generating Capacity Resource, New Import Capacity Resource or New Demand Capacity Resource participate in the Forward Capacity Market, as described in Section III.13.

Proxy De-List Bid is a type of bid used in the Forward Capacity Market.

Provisional Member is defined in Section I.68A of the Restated NEPOOL Agreement.

PTO Administrative Committee is the committee referred to in Section 11.04 of the TOA.

Public Policy Requirement is a requirement reflected in a statute enacted by, or a regulation promulgated by, the federal government or a state or local (e.g., municipal or county) government.

Public Policy Transmission Study is a study conducted by the ISO pursuant to the process set out in Section 4A.3 of Attachment K of the OATT, and consists of two phases: (i) an initial phase to produce a rough estimate of the costs and benefits of concepts that could meet transmission needs driven by public policy requirements; and (ii) a follow-on phase designed to produce more detailed analysis and engineering work on transmission concepts identified in the first phase.

Public Policy Local Transmission Study is a study conducted by a PTO pursuant to the process set out in Section 1.6 of Attachment K Appendix 1 of the OATT, and consists of two phases: (i) an initial phase to produce an estimate of the costs and benefits of concepts that could meet transmission needs driven by public policy requirements; and (ii) a follow-on phase designed to produce more detailed analysis and engineering work on transmission concepts identified in the first phase.

Public Policy Transmission Upgrade is an addition and/or upgrade to the New England Transmission System that meets the voltage and non-voltage criteria for Public Policy Transmission Upgrade PTF classification specified in the OATT, and has been included in the Regional System Plan and RSP Project List as a Public Policy Transmission Upgrade pursuant to the procedures described in Section 4A of Attachment K of the OATT.

Publicly Owned Entity is defined in Section I of the Restated NEPOOL Agreement.

Qualification Process Cost Reimbursement Deposit is described in Section III.13.1.9.3 of Market Rule 1.

Qualified Capacity is the amount of capacity a resource may provide in the summer or winter in a Capacity Commitment Period, as determined in the Forward Capacity Market qualification processes.

Qualified Generator Reactive Resource(s) is any generator source of dynamic reactive power that meets the criteria specified in Schedule 2 of the OATT.

Qualified Non-Generator Reactive Resource(s) is any non-generator source of dynamic reactive power that meets the criteria specified in Schedule 2 of the OATT.

Qualified Reactive Resource(s) is any Qualified Generator Reactive Resource and/or Qualified Non-Generator Reactive Resource that meets the criteria specified in Schedule 2 of the OATT.

Qualified Transmission Project Sponsor is defined in Sections 4B.2 and 4B.3 of Attachment K of the OATT.

Queue Position has the meaning specified in Section I of Schedule 22, Attachment 1 to Schedule 23, and Section I of Schedule 25 of the OATT.

Rapid Response Pricing Asset is: (i) a Fast Start Generator; (ii) a Flexible DNE Dispatchable Generator; or (iii) a Binary Storage DARD with Offer Data specifying a Minimum Run Time and a Minimum Down Time not exceeding one hour each. A Rapid Response Pricing Asset shall also include a Fast Start Demand Response Resource for which the Market Participant's Offer Data meets the following criteria: (i) Minimum Reduction Time does not exceed one hour; and (ii) Demand Response Resource Notification Time plus Demand Response Resource Start-Up Time does not exceed 30 minutes.

Rapid Response Pricing Opportunity Cost is the NCPC Credit described in Section III.F.2.3.10.

Rated means a Market Participant that receives a credit rating from one or more of the Rating Agencies, or, if such Market Participant is not rated by one of the Rating Agencies, then a Market Participant that has outstanding unsecured debt rated by one or more of the Rating Agencies.

Rating Agencies are Standard and Poor's (S&P), Moody's, and Fitch.

Rationing Minimum Limit is the MW quantity for a New Generating Capacity Resource or Existing Generating Capacity Resource below which n offer or bid may not be rationed in the Forward Capacity Auction, but shall not apply to supply offers or demand bids in a substitution auction as specified in Section III.13.2.8.2 and Section III.13.2.8.3.

RBA Decision is a written decision provided by the ISO to a Disputing Party and to the Chair of the NEPOOL Budget and Finance Subcommittee accepting or denying a Requested Billing Adjustment within twenty Business Days of the date the ISO distributes a Notice of RBA, unless some later date is agreed upon by the Disputing Party and the ISO.

Reactive Capability Audit is an audit that measures the ability of a Reactive Resource to provide or absorb reactive power to or from the transmission system at a specified real power output or consumption.

Reactive Resource is a device that dynamically adjusts reactive power output automatically in Real-Time over a continuous range, taking into account control system response bandwidth, within a specified voltage bandwidth in response to grid voltage changes. These resources operate to maintain a set-point

voltage and include, but are not limited to, Generator Assets, Dispatchable Asset Related Demands that are part of an Electric Storage Facility, and dynamic transmission devices.

Reactive Supply and Voltage Control Service is the form of Ancillary Service described in Schedule 2 of the OATT.

Real-Time is a period in the current Operating Day for which the ISO dispatches Resources for energy and Regulation, designates Resources for Regulation and Operating Reserve and, if necessary, commits additional Resources.

Real-Time Adjusted Load Obligation is defined in Section III.3.2.1(b) of Market Rule 1.

Real-Time Adjusted Load Obligation Deviation is defined in Section III.3.2.1(d) of Market Rule 1.

Real-Time Commitment NCPC Credit is an NCPC Credit calculated pursuant to Appendix F to Market Rule 1.

Real-Time Congestion Revenue is defined in Section III.3.2.1(i) of Market Rule 1.

Real-Time Demand Reduction Obligation is defined in Section III.3.2.1(c) of Market Rule 1.

Real-Time Demand Reduction Obligation Deviation is defined in Section III.3.2.1(e) of Market Rule 1.

Real-Time Dispatch NCPC Credit is an NCPC Credit calculated pursuant to Appendix F to Market Rule 1.

Real-Time Energy Inventory is a component of the spot payment that a Market Participant may receive through the inventoried energy program, as described in Section III.K.3.2.1 of Market Rule 1.

Real-Time Energy Market means the purchase or sale of energy, purchase of demand reductions, payment of Congestion Costs, and payment for losses for quantity deviations from the Day-Ahead Energy Market in the Operating Day and designation of and payment for provision of Operating Reserve in Real-Time.

Real-Time Energy Market Deviation Congestion Charge/Credit is defined in Section III.3.2.1(g) of Market Rule 1.

Real-Time Energy Market Deviation Energy Charge/Credit is defined in Section III.3.2.1(g) of Market Rule 1.

Real-Time Energy Market Deviation Loss Charge/Credit is defined in Section III.3.2.1(g) of Market Rule 1.

Real-Time Energy Market NCPC Credits are the Real-Time Commitment NCPC Credit and the Real-Time Dispatch NCPC Credit.

Real-Time External Transaction NCPC Credit is an NCPC Credit calculated pursuant to Appendix F to Market Rule 1.

Real-Time Generation Obligation is defined in Section III.3.2.1(b) of Market Rule 1.

Real-Time Generation Obligation Deviation is defined in Section III.3.2.1(d) of Market Rule 1.

Real-Time High Operating Limit is the maximum output, in MW, of a Generator Asset that could be achieved, consistent with Good Utility Practice, in response to an ISO request for Energy (including pursuant to Section III.13.6.4 of Market Rule 1), for each hour of the Operating Day, as reflected in the Generator Asset's Offer Data. This value is based on real-time operating conditions and the physical operating characteristics and operating permits of the facility and must be submitted for all Generator Assets (other than Settlement Only Resources).

Real-Time Load Obligation is defined in Section III.3.2.1(b) of Market Rule 1.

Real-Time Load Obligation Deviation is defined in Section III.3.2.1(d) of Market Rule 1.

Real-Time Locational Adjusted Net Interchange is defined in Section III.3.2.1(b) of Market Rule 1.

Real-Time Locational Adjusted Net Interchange Deviation is defined in Section III.3.2.1(d) of Market Rule 1.

Real-Time Loss Revenue is defined in Section III.3.2.1(l) of Market Rule 1.

Real-Time Loss Revenue Charges or Credits are defined in Section III.3.2.1(m) of Market Rule 1.

Real-Time NCP Load Obligation is the maximum hourly value, during a month, of a Market Participant's Real-Time Load Obligation summed over all Locations, excluding exports, in kilowatts.

Real-Time Offer Change is a modification to a Supply Offer pursuant to Section III.1.10.9(b).

Real-Time Posturing NCPC Credit for Generators (Other Than Limited Energy Resources) Postured for Reliability is an NCPC Credit calculated pursuant to Appendix F to Market Rule 1.

Real-Time Posturing NCPC Credit for Limited Energy Resources Postured for Reliability is an NCPC Credit calculated pursuant to Appendix F to Market Rule 1.

Real-Time Prices means the Locational Marginal Prices resulting from the ISO's dispatch of the New England Markets in the Operating Day.

Real-Time Reserve Charge is a Market Participant's share of applicable system and Reserve Zone Real-Time Operating Reserve costs attributable to meeting the Real-Time Operating Reserve requirement as calculated in accordance with Section III.10 of Market Rule 1.

Real-Time Reserve Clearing Price is the Real-Time TMSR, TMNSR or TMOR clearing price, as applicable, for the system and each Reserve Zone that is calculated in accordance with Section III.2.7A of Market Rule 1.

Real-Time Reserve Credit is a Market Participant's compensation associated with that Market Participant's Resources' Reserve Quantity For Settlement as calculated in accordance with Section III.10 of Market Rule 1.

Real-Time Reserve Designation is the amount, in MW, of Operating Reserve designated to a Resource in Real-Time by the ISO as described in Section III.1.7.19 of Market Rule 1.

Real-Time Reserve Opportunity Cost is defined in Section III.2.7A(b) of Market Rule 1.

Real-Time Synchronous Condensing NCPC Credit is an NCPC Credit calculated pursuant to Appendix F to Market Rule 1.

Real-Time System Adjusted Net Interchange means, for each hour, the sum of Real-Time Locational Adjusted Net Interchange for a Market Participant over all Locations, in kilowatts.

Receiving Party is the entity receiving the capacity and/or energy transmitted to Point(s) of Delivery under the OATT.

Reference Level is defined in Section III.A.5.7 of Appendix A of Market Rule 1.

Regional Benefit Upgrade(s) (RBU) means a Transmission Upgrade that: (i) is rated 115kV or above; (ii) meets all of the non-voltage criteria for PTF classification specified in the OATT; and (iii) is included in the Regional System Plan as either a Reliability Transmission Upgrade or a Market Efficiency Transmission Upgrade identified as needed pursuant to Attachment K of the OATT. The category of RBU shall not include any Transmission Upgrade that has been categorized under any of the other categories specified in Schedule 12 of the OATT (e.g., an Elective Transmission Upgrade shall not also be categorized as an RBU). Any upgrades to transmission facilities rated below 115kV that were PTF prior to January 1, 2004 shall remain classified as PTF and be categorized as an RBU if, and for so long as, such upgrades meet the criteria for PTF specified in the OATT.

Regional Network Load is the load that a Network Customer designates for Regional Network Service under Part II.B of the OATT. The Network Customer's Regional Network Load shall include all load designated by the Network Customer (including losses) and shall not be credited or reduced for any behind-the-meter generation. A Network Customer may elect to designate less than its total load as Regional Network Load but may not designate only part of the load at a discrete Point of Delivery. Where a Transmission Customer has elected not to designate a particular load at discrete Points of Delivery as Regional Network Load, the Transmission Customer is responsible for making separate arrangements

under Part II.C of the OATT for any Point-To-Point Service that may be necessary for such non-designated load.

Regional Network Service (RNS) is the transmission service over the PTF described in Part II.B of the OATT, including such service which is used with respect to Network Resources or Regional Network Load that is not physically interconnected with the PTF.

Regional Planning Dispute Resolution Process is described in Section 12 of Attachment K to the OATT.

Regional System Plan (RSP) is the plan developed under the process specified in Attachment K of the OATT.

Regional Transmission Service (RTS) is Regional Network Service and Through or Out Service as provided over the PTF in accordance with Section II.B, Section II.C, Schedule 8 and Schedule 9 of the OATT.

Regulation is the capability of a specific Resource with appropriate telecommunications, control and response capability to respond to an AGC SetPoint.

Regulation and Frequency Response Service is the form of Ancillary Service described in Schedule 3 of the OATT. The capability of performing Regulation and Frequency Response Service is referred to as automatic generation control (AGC).

Regulation Capacity is the lesser of five times the Automatic Response Rate and one-half of the difference between the Regulation High Limit and the Regulation Low Limit of a Resource capable of providing Regulation.

Regulation Capacity Requirement is the amount of Regulation Capacity required to maintain system control and reliability in the New England Control Area as calculated and posted on the ISO website.

Regulation Capacity Offer is an offer by a Market Participant to provide Regulation Capacity.

Regulation High Limit is an offer parameter that establishes the upper bound for AGC SetPoints and is used in the determination of a Resource's Regulation Capacity.

Regulation Low Limit is an offer parameter that establishes the lower bound for AGC SetPoints and is used in the determination of a Resource's Regulation Capacity.

Regulation Market is the market described in Section III.14 of Market Rule 1.

Regulation Resources are those Alternative Technology Regulation Resources and Generator Assets that satisfy the requirements of Section III.14.2. Regulation Resources are eligible to participate in the Regulation Market.

Regulation Service is the change in output or consumption made in response to changing AGC SetPoints.

Regulation Service Requirement is the estimated amount of Regulation Service required to maintain system control and reliability in the New England Control Area as calculated and posted on the ISO website.

Regulation Service Offer is an offer by a Market Participant to provide Regulation Service.

Related Person is defined pursuant to Section 1.1 of the Participants Agreement.

Related Transaction is defined in Section III.1.4.3 of Market Rule 1.

Reliability Administration Service (RAS) is the service provided by the ISO, as described in Schedule 3 of Section IV.A of the Tariff, in order to administer the Reliability Markets and provide other reliability-related and informational functions.

Reliability Committee is the committee whose responsibilities are specified in Section 8.2.3 of the Participants Agreement.

Reliability Markets are, collectively, the ISO's administration of Regulation, the Forward Capacity Market, and Operating Reserve.

Reliability Region means any one of the regions identified on the ISO's website. Reliability Regions are intended to reflect the operating characteristics of, and the major transmission constraints on, the New England Transmission System.

Reliability Transmission Upgrade means those additions and upgrades not required by the interconnection of a generator that are nonetheless necessary to ensure the continued reliability of the New England Transmission System, taking into account load growth and known resource changes, and include those upgrades necessary to provide acceptable stability response, short circuit capability and system voltage levels, and those facilities required to provide adequate thermal capability and local voltage levels that cannot otherwise be achieved with reasonable assumptions for certain amounts of generation being unavailable (due to maintenance or forced outages) for purposes of long-term planning studies. Good Utility Practice, applicable reliability principles, guidelines, criteria, rules, procedures and standards of ERO and NPCC and any of their successors, applicable publicly available local reliability criteria, and the ISO System Rules, as they may be amended from time to time, will be used to define the system facilities required to maintain reliability in evaluating proposed Reliability Transmission Upgrades. A Reliability Transmission Upgrade may provide market efficiency benefits as well as reliability benefits to the New England Transmission System.

Remittance Advice is an issuance from the ISO for the net Payment owed to a Covered Entity where a Covered Entity's total Payments exceed its total Charges in a billing period.

Remittance Advice Date is the day on which the ISO issues a Remittance Advice.

Renewable Technology Resource is a Generating Capacity Resource or an On-Peak Demand Resource that satisfies the requirements specified in Section III.13.1.1.1.7.

Re-Offer Period is the period that normally occurs between the posting of the of the Day-Ahead Energy Market results and 2:00 p.m. on the day before the Operating Day during which a Market Participant may submit revised Supply Offers, revised External Transactions, or revised Demand Bids associated with Dispatchable Asset Related Demands or, revised Demand Reduction Offers associated with Demand Response Resources.

Replacement Reserve is described in Part III, Section VII of ISO New England Operating Procedure No. 8.

Request for Alternative Proposals (RFAP) is the request described in Attachment K of the OATT.

Requested Billing Adjustment (RBA) is defined in Section 6.1 of the ISO New England Billing Policy.

Required Balance is an amount as defined in Section 5.3 of the Billing Policy.

Reseller is a MGTSA holder that sells, assigns or transfers its rights under its MGTSA, as described in Section II.45.1(a) of the OATT.

Reserve Adequacy Analysis is the analysis performed by the ISO to determine if adequate Resources are committed to meet forecasted load, Operating Reserve, and security constraint requirements for the current and next Operating Day.

Reserve Constraint Penalty Factors (RCPFs) are rates, in $/MWh, that are used within the Real-Time dispatch and pricing algorithm to reflect the value of Operating Reserve shortages and are defined in Section III.2.7A(c) of Market Rule 1; and, commencing on June 1, 2024, that are used within the Day-Ahead Energy Market security-constrained economic commitment and dispatch process to reflect the value of Day-Ahead Ancillary Services shortages and forecast energy requirement shortages and are defined in Section III.2.6.2(b) of Market Rule 1.

Reserve Quantity For Settlement is defined in Section III.10.1 of Market Rule 1.

Reserve Zone is defined in Section III.2.7 of Market Rule 1.

Reserved Capacity is the maximum amount of capacity and energy that is committed to the Transmission Customer for transmission over the New England Transmission System between the Point(s) of Receipt and the Point(s) of Delivery under Part II.C or Schedule 18, 20 or 21 of the OATT, as applicable. Reserved Capacity shall be expressed in terms of whole kilowatts on a sixty-minute interval (commencing on the clock hour) basis, or, in the case of Reserved Capacity for Local Point-to-Point Service, in terms of whole megawatts on a sixty-minute interval basis.

Resource means a Generator Asset, a Dispatchable Asset Related Demand, an External Resource, an External Transaction, or a Demand Response Resource.

Restated New England Power Pool Agreement (RNA) is the Second Restated New England Power Pool Agreement, which restated for a second time by an amendment dated as of August 16, 2004 the New England Power Pool Agreement dated September 1, 1971, as the same may be amended and restated from time to time, governing the relationship among the NEPOOL members.

Rest-of-Pool Capacity Zone is a single Capacity Zone made up of the adjacent Load Zones that are neither export-constrained nor import-constrained.

Rest of System is an area established under Section III.2.7(d) of Market Rule 1.

Retail Delivery Point is the point on the transmission or distribution system at which the load of an end-use facility, which is metered and assigned a unique account number by the Host Participant, is measured to determine the amount of energy delivered to the facility from the transmission and distribution system. If an end-use facility is connected to the transmission or distribution system at more than one location, the Retail Delivery Point shall consist of the metered load at each connection point, summed to measure the net energy delivered to the facility in each interval.

Retirement De-List Bid is a bid to retire an Existing Generating Capacity Resource, Existing Import Capacity Resource, or Existing Demand Capacity Resource from all New England Markets, as described in Section III.13.1.2.3.1.5.

Returning Market Participant is a Market Participant, other than an FTR-Only Customer or a Governance Only Member, whose previous membership as a Market Participant was involuntarily terminated due to a Financial Assurance Default or a payment default and, since returning, has been a Market Participant for less than six consecutive months.

Revenue Requirement is defined in Section IV.A.2.1 of the Tariff.

Reviewable Action is defined in Section III.D.1.1 of Appendix D of Market Rule 1.

Reviewable Determination is defined in Section 12.4(a) of Attachment K to the OATT.

RSP Project List is defined in Section 1 of Attachment K to the OATT.

RTEP02 Upgrade(s) means a Transmission Upgrade that was included in the annual NEPOOL Transmission Plan (also known as the "Regional Transmission Expansion Plan" or "RTEP") for the year 2002, as approved by ISO New England Inc.'s Board of Directors, or the functional equivalent of such Transmission Upgrade, as determined by ISO New England Inc. The RTEP02 Upgrades are listed in Schedule 12B of the OATT.

RTO is a regional transmission organization or comparable independent transmission organization that complies with Order No. 2000 and the Commission's corresponding regulation.

Same Reserve Zone Export Transaction is defined in Section III.1.10.7(f)(iii) of Market Rule 1.

Sanctionable Behavior is defined in Section III.B.3 of Appendix B of Market Rule 1.

Schedule, Schedules, Schedule 1, 2, 3, 4 and 5 are references to the individual or collective schedules to Section IV.A. of the Tariff.

Schedule 20A Service Provider (SSP) is defined in Schedule 20A to Section II of this Tariff.

Scheduling Service, for purposes of Section IV.A and Section IV.B of the Tariff, is the service described in Schedule 1 to Section IV.A of the Tariff.

Scheduling, System Control and Dispatch Service, for purposes of Section II of the Tariff, is the form of Ancillary Service described in Schedule 1 of the OATT.

Seasonal Claimed Capability is the summer or winter claimed capability of a Generator Asset or Generating Capacity Resource, and represents the maximum dependable load carrying ability of the asset or resource, excluding capacity required for station use.

Seasonal Claimed Capability Audit is the Generator Asset audit performed pursuant to Section III.1.5.1.3.

Seasonal DR Audit is the Demand Response Resource audit performed pursuant to Section III.1.5.1.3.1.

Seasonal Peak Demand Resource is a type of Demand Capacity Resource and shall mean installed measures (e.g., products, equipment, systems, services, practices and/or strategies) on end-use customer facilities that reduce the total amount of electrical energy consumed during Demand Resource Seasonal Peak Hours, while delivering a comparable or acceptable level of end-use service. Such measures include Energy Efficiency, Load Management, and Distributed Generation.

Section III.1.4 Transactions are defined in Section III.1.4.2 of Market Rule 1.

Section III.1.4 Conforming Transactions are defined in Section III.1.4.2 of Market Rule 1.

Security Agreement is Attachment 1 to the ISO New England Financial Assurance Policy.

Selected Qualified Transmission Project Sponsor is the Qualified Transmission Project Sponsor that proposed the Phase Two or Stage Two Solution that has been identified by the ISO as the preferred Phase Two or Stage Two Solution.

Selected Qualified Transmission Project Sponsor Agreement is the agreement between the ISO and a Selected Qualified Transmission Project Sponsor. The Selected Qualified Transmission Project Sponsor Agreement is provided in Attachment P to the OATT.

Self-Schedule is the action of a Market Participant in committing its Generator Asset or DARD, in accordance with applicable ISO New England Manuals, to provide service in an hour, whether or not in the absence of that action the Generator Asset or DARD would have been committed by the ISO to provide the service. For a Generator Asset, Self-Schedule is the action of a Market Participant in committing a Generator Asset to provide Energy in an hour at its Economic Minimum Limit, whether or not in the absence of that action the Generator Asset would have been committed by the ISO to provide the Energy. For a DARD, Self-Schedule is the action of a Market Participant in committing a DARD to consume Energy in an hour at its Minimum Consumption Limit, whether or not in the absence of that action the DARD would have been committed by the ISO to consume Energy. For an External Transaction, a Self-Schedule is a request by a Market Participant for the ISO to select the External Transaction regardless of the LMP. Demand Response Resources are not permitted to Self-Schedule.

Self-Supplied FCA Resource is described in Section III.13.1.6 of Market Rule 1.

Senior Officer means an officer of the subject entity with the title of vice president (or similar office) or higher, or another officer designated in writing to the ISO by that office.

Service Agreement is a Transmission Service Agreement or an MPSA.

Service Commencement Date is the date service is to begin pursuant to the terms of an executed Service Agreement, or the date service begins in accordance with the sections of the OATT addressing the filing of unexecuted Service Agreements.

Services means, collectively, the Scheduling Service, EAS and RAS; individually, a Service.

Settlement Financial Assurance is an amount of financial assurance required from a Designated FTR Participant awarded a bid in an FTR Auction. This amount is calculated pursuant to Section VI.C of the ISO New England Financial Assurance Policy.

Settlement Only Resources are generators of less than 5 MW or otherwise eligible for Settlement Only Resource treatment as described in ISO New England Operating Procedure No. 14 and that have elected Settlement Only Resource treatment as described in the ISO New England Manual for Registration and Performance Auditing.

Shortfall Funding Arrangement, as specified in Section 5.1 of the ISO New England Billing Policy, is a separate financing arrangement that can be used to make up any non-congestion related differences between amounts received on Invoices and amounts due for ISO Charges in any bill issued.

Short-Term is a period of less than one year.

Significantly Reduced Congestion Costs are defined in Section III.G.2.2 of Appendix G to Market Rule 1.

SMD Effective Date is March 1, 2003.

Solutions Study is described in Section 4.2(b) of Attachment K to the OATT.

Special Constraint Resource (SCR) is a Resource that provides Special Constraint Resource Service under Schedule 19 of the OATT.

Special Constraint Resource Service is the form of Ancillary Service described in Schedule 19 of the OATT.

Specified-Term Blackstart Capital Payment is the annual compensation level, as calculated pursuant to Section 5.1 of Schedule 16 of the OATT, for a Designated Blackstart Resource's capital Blackstart Equipment costs associated with the provision of Blackstart Service (except for capital costs associated with adhering to NERC Critical Infrastructure Protection Reliability Standards as part of Blackstart Service).

Sponsored Policy Resource is a New Capacity Resource that: receives an out-of-market revenue source supported by a government-regulated rate, charge or other regulated cost recovery mechanism, and; qualifies as a renewable, clean or alternative energy resource under a renewable energy portfolio standard, clean energy standard, alternative energy portfolio standard, renewable energy goal, or clean energy goal enacted (either by statute or regulation) in the New England state from which the resource receives the out-of-market revenue source and that is in effect on January 1, 2018.

Stage One Proposal is a first round submission, as defined in Sections 4A.5 of Attachment K of the OATT, of a proposal for a Public Policy Transmission Upgrade by a Qualified Transmission Project Sponsor.

Stage Two Solution is a second round submission, as defined in Section 4A.5 of Attachment K of the OATT, of a proposal for a Public Policy Transmission Upgrade by a Qualified Transmission Project Sponsor.

Standard Blackstart Capital Payment is the annual compensation level, as calculated pursuant to Section 5.1 of Schedule 16 of the OATT, for a Designated Blackstart Resource's capital Blackstart Equipment costs associated with the provision of Blackstart Service (except for capital costs associated with adhering to NERC Critical Infrastructure Protection Reliability Standards as part of Blackstart Service).

Start-of-Round Price is the highest price associated with a round of a Forward Capacity Auction as described in Section III.13.2.3.1 of Market Rule 1.

Start-Up Fee is the amount, in dollars, that must be paid for a Generator Asset to Market Participants with an Ownership Share in the Generator Asset each time the Generator Asset is scheduled in the New England Markets to start-up.

Start-Up Time is the time it takes the Generator Asset, after synchronizing to the system, to reach its Economic Minimum Limit and, for dispatchable Generator Assets, be ready for further dispatch by the ISO.

State Estimator means the computer model of power flows specified in Section III.2.3 of Market Rule 1.

Statements, for the purpose of the ISO New England Billing Policy, refer to both Invoices and Remittance Advices.

Static De-List Bid is a bid that may be submitted by an Existing Generating Capacity Resource, Existing Import Capacity Resource, or Existing Demand Capacity Resource in the Forward Capacity Auction to remove itself from the capacity market for a one year period, as described in Section III.13.1.2.3.1.1 of Market Rule 1.

Station is one or more Existing Generating Capacity Resources consisting of one or more assets located within a common property boundary.

Station Going Forward Common Costs are the net costs associated with a Station that are avoided only by the clearing of the Static De-List Bids, the Permanent De-List Bids or the Retirement De-List Bids of all the Existing Generating Capacity Resources comprising the Station.

Station-level Blackstart O&M Payment is defined and calculated as specified in Section 5.1.2 of Schedule 16 to the OATT.

Station-level Specified-Term Blackstart Capital Payment is defined and calculated as specified in Section 5.1.2 of Schedule 16 to the OATT.

Station-level Standard Blackstart Capital Payment is defined and calculated as specified in Section 5.1.2 of Schedule 16 to the OATT.

Storage DARD is a DARD that participates in the New England Markets as part of an Electric Storage Facility, as described in Section III.1.10.6 of Market Rule 1.

Summer ARA Qualified Capacity is described in Section III.13.4.2.1.2.1.1.1 of Market Rule 1.

Summer Capability Period means one of two time periods defined by the ISO for the purposes of rating and auditing resources pursuant to Section III.9. The time period associated with the Summer Capability Period is the period of June 1 through September 30.

Summer Intermittent Reliability Hours are defined in Section III.13.1.2.2.2.1(c) of Market Rule 1.

Supply Offer is a proposal to furnish energy at a Node or Regulation from a Resource that meets the applicable requirements set forth in the ISO New England Manuals submitted to the ISO by a Market Participant with authority to submit a Supply Offer for the Resource. The Supply Offer will be submitted pursuant to Market Rule 1 and applicable ISO New England Manuals, and include a price and information with respect to the quantity proposed to be furnished, technical parameters for the Resource, timing and other matters. A Supply Offer is a subset of the information required in a Market Participant's Offer Data.

Supply Offer Block-Hours are Block-Hours assigned to the Lead Market Participant for each Supply Offer. Blocks of the Supply Offer in effect for each hour will be totaled to determine the quantity of Supply Offer Block-Hours for a given day. In the case that a Resource has a Real-Time unit status of "unavailable" for the entire day, that day will not contribute to the quantity of Supply Offer Block-Hours. However, if the Resource has at least one hour of the day with a unit status of "available," the entire day will contribute to the quantity of Supply Offer Block-Hours.

Synchronous Condenser is a generator that is synchronized to the grid but supplying no energy for the purpose of providing Operating Reserve or VAR or voltage support.

System Condition is a specified condition on the New England Transmission System or on a neighboring system, such as a constrained transmission element or flowgate, that may trigger Curtailment of Long-

Term Firm MTF or OTF Service on the MTF or the OTF using the curtailment priority pursuant to Section II.44 of the Tariff or Curtailment of Local Long-Term Firm Point-to-Point Transmission Service on the non-PTF using the curtailment priority pursuant to Schedule 21 of the Tariff. Such conditions must be identified in the Transmission Customer's Service Agreement.

System Impact Study is an assessment pursuant to Part II.B, II.C, II.G, Schedule 21, Schedule 22, Schedule 23, or Schedule 25 of the OATT of (i) the adequacy of the PTF or Non-PTF to accommodate a request for the interconnection of a new or materially changed generating unit or a new or materially changed interconnection to another Control Area or new Regional Network Service or new Local Service or an Elective Transmission Upgrade, and (ii) whether any additional costs may be required to be incurred in order to provide the interconnection or transmission service.

System Operator shall mean ISO New England Inc. or a successor organization.

System Operating Limit (SOL) has the meaning specified in the Glossary of Terms Used in NERC Reliability Standards.

System-Wide Capacity Demand Curve is the demand curve used in the Forward Capacity Market as specified in Section III.13.2.2.

TADO is the total amount due and owing (not including any amounts due under Section 14.1 of the RNA) at such time to the ISO, NEPOOL, the PTOs, the Market Participants and the Non-Market Participant Transmission Customers, by all PTOs, Market Participants and Non-Market Participant Transmission Customers.

Tangible Net Worth is the value, determined in accordance with international accounting standards or generally accepted accounting principles in the United States, of all of that entity's assets less the following: (i) assets the ISO reasonably believes to be restricted or potentially unavailable to settle a claim in the event of a default (e.g., regulatory assets, restricted assets, and Affiliate assets), net of any matching liabilities, to the extent that the result of that netting is a positive value; (ii) derivative assets, net of any matching liabilities, to the extent that the result of that netting is a positive value; (iii) the amount at which the liabilities of the entity would be shown on a balance sheet in accordance with international accounting standards or generally accepted accounting principles in the United States; (iv) preferred stock: (v) non-controlling interest; and (vi) all of that entity's intangible assets (e.g., patents, trademarks,

franchises, intellectual property, goodwill and any other assets not having a physical existence), in each case as shown on the most recent financial statements provided by such entity to the ISO.

Technical Committee is defined in Section 8.2 of the Participants Agreement.

Ten-Minute Non-Spinning Reserve (TMNSR) is a form of ten-minute reserve capability, determined pursuant to Section III.1.7.19.2.

Ten-Minute Non-Spinning Reserve Service is the form of Ancillary Service described in Schedule 6 of the OATT.

Ten-Minute Reserve Requirement is the combined amount of TMSR and TMNSR required system-wide as described in Section III.2.7A and ISO New England Operating Procedure No. 8.

Ten-Minute Spinning Reserve (TMSR) is a form of ten-minute reserve capability, determined pursuant to Section III.1.7.19.2.

Ten-Minute Spinning Reserve Requirement is the amount of TMSR required system-wide as described in Section III.2.7A and ISO New England Operating Procedure No. 8.

Ten-Minute Spinning Reserve Service is the form of Ancillary Service described in Schedule 5 of the OATT.

Third-Party Sale is any sale for resale in interstate commerce to a Power Purchaser that is not designated as part of Regional Network Load or Local Network Load under the Regional Network Service or Local Network Service, as applicable.

Thirty-Minute Operating Reserve (TMOR) is a form of thirty-minute reserve capability, determined pursuant to Section III.1.7.19.2.

Thirty-Minute Operating Reserve Service is the form of Ancillary Service described in Schedule 7 of the OATT.

Through or Out Rate (TOUT Rate) is the rate per hour for Through or Out Service, as defined in Section II.25.2 of the OATT.

Through or Out Service (TOUT Service) means Point-To-Point Service over the PTF provided by the ISO with respect to a transaction that goes through the New England Control Area, as, for example, a single transaction where energy or capacity is transmitted into the New England Control Area from New Brunswick and subsequently out of the New England Control Area to New York, or a single transaction where energy or capacity is transmitted into the New England Control Area from New York through one point on the PTF and subsequently flows over the PTF prior to passing out of the New England Control Area to New York, or with respect to a transaction which originates at a point on the PTF and flows over the PTF prior to passing out of the New England Control Area, as, for example, from Boston to New York.

Tie-Line Asset is a physical transmission tie-line, or an inter-state or intra-state border arrangement created according to the ISO New England Manuals and registered in accordance with the Asset Registration Process.

Total Available Amount is the sum of the available amount of the Shortfall Funding Arrangement and the balance in the Payment Default Shortfall Fund.

Total Blackstart Capital Payment is the annual compensation calculated under either Section 5.1 or Section 5.2 of Schedule 16 of the OATT, as applicable.

Total Blackstart Service Payments is monthly compensation to Blackstart Owners or Market Participants, as applicable, and as calculated pursuant to Section 5.6 of Schedule 16 to the OATT.

Total Reserve Requirement, which includes Replacement Reserve, is the combined amount of TMSR, TMNSR, and TMOR required system-wide as described in Section III.2.7A and ISO New England Operating Procedure No. 8.

Total System Capacity is the aggregate capacity supply curve for the New England Control Area as determined in accordance with Section III.13.2.3.3 of Market Rule 1.

Transaction Unit (TU) is a type of billing determinant under Schedule 2 of Section IV.A of the Tariff used to assess charges to Customers.

Transition Period: The six-year period commencing on March 1, 1997.

Transmission Charges, for the purposes of the ISO New England Financial Assurance Policy and the ISO New England Billing Policy, are all charges and payments under Schedules 1, 8 and 9 of the OATT.

Transmission Congestion Credit means the allocated share of total Transmission Congestion Revenue credited to each holder of Financial Transmission Rights, calculated and allocated as specified in Section III.5.2 of Market Rule 1.

Transmission Congestion Revenue is defined in Section III.5.2.5(a) of Market Rule 1.

Transmission Constraint Penalty Factors are described in Section III.1.7.5 of Market Rule 1.

Transmission Credit Limit is a credit limit, not to be used to meet FTR Requirements, established for each Market Participant in accordance with Section II.D and each Non-Market Participant Transmission Customer in accordance with Section V.B.2 of the ISO New England Financial Assurance Policy.

Transmission Credit Test Percentage is calculated in accordance with Section III.B.1(c) of the ISO New England Financial Assurance Policy.

Transmission Customer is any Eligible Customer that (i) executes, on its own behalf or through its Designated Agent, an MPSA or TSA, or (ii) requests in writing, on its own behalf or through its Designated Agent, that the ISO, the Transmission Owner, or the Schedule 20A Service Provider, as applicable, file with the Commission, a proposed unexecuted MPSA or TSA containing terms and conditions deemed appropriate by the ISO (in consultation with the applicable PTO, OTO or Schedule 20A Service Provider) in order that the Eligible Customer may receive transmission service under Section II of this Tariff. A Transmission Customer under Section II of this Tariff includes a Market Participant or a Non-Market Participant taking Regional Network Service, Through or Out Service, MTF Service, OTF Service, Ancillary Services, or Local Service.

Transmission Default Amount is all or any part of any amount of Transmission Charges due to be paid by any Covered Entity that the ISO, in its reasonable opinion, believes will not or has not been paid when due.

Transmission Default Period is defined in Section 3.4.f of the ISO New England Billing Policy.

Transmission Late Payment Account is defined in Section 4.2 of the ISO New England Billing Policy.

Transmission Late Payment Account Limit is defined in Section 4.2 of the ISO New England Billing Policy.

Transmission Late Payment Charge is defined in Section 4.1 of the ISO New England Billing Policy.

Transmission, Markets and Services Tariff (Tariff) is the ISO New England Inc. Transmission, Markets and Services Tariff, as amended from time to time.

Transmission Obligations are determined in accordance with Section III.A(vi) of the ISO New England Financial Assurance Policy.

Transmission Operating Agreement (TOA) is the Transmission Operating Agreement between and among the ISO and the PTOs, as amended and restated from time to time.

Transmission Owner means a PTO, MTO or OTO.

Transmission Provider is the ISO for Regional Network Service and Through or Out Service as provided under Section II.B and II.C of the OATT; Cross-Sound Cable, LLC for Merchant Transmission Service as provided under Schedule 18 of the OATT; the Schedule 20A Service Providers for Phase I/II HVDC-TF Service as provided under Schedule 20A of the OATT; and the Participating Transmission Owners for Local Service as provided under Schedule 21 of the OATT.

Transmission Requirements are determined in accordance with Section III.A(iii) of the ISO New England Financial Assurance Policy.

Transmission Security Analysis Requirement shall be determined pursuant to Section III.12.2.1.2.

Transmission Service Agreement (TSA) is the initial agreement and any amendments or supplements thereto: (A) in the form specified in either Attachment A or B to the OATT, entered into by the Transmission Customer and the ISO for Regional Network Service or Through or Out Service; (B) entered into by the Transmission Customer with the ISO and PTO in the form specified in Attachment A to Schedule 21 of the OATT; (C) entered into by the Transmission Customer with an OTO or Schedule 20A Service Provider in the appropriate form specified under Schedule 20 of the OATT; or (D) entered into by the Transmission Customer with a MTO in the appropriate form specified under Schedule 18 of the OATT. A Transmission Service Agreement shall be required for Local Service, MTF Service and OTF Service, and shall be required for Regional Network Service and Through or Out Service if the Transmission Customer has not executed a MPSA.

Transmission Upgrade(s) means an upgrade, modification or addition to the PTF that becomes subject to the terms and conditions of the OATT governing rates and service on the PTF on or after January 1, 2004. This categorization and cost allocation of Transmission Upgrades shall be as provided for in Schedule 12 of the OATT.

UDS is unit dispatch system software.

Unconstrained Export Transaction is defined in Section III.1.10.7(f)(iv) of Market Rule 1.

Uncovered Default Amount is defined in Section 3.3(i) of the ISO New England Billing Policy.

Uncovered Transmission Default Amounts are defined in Section 3.4.f of the ISO New England Billing Policy.

Unrated means a Market Participant that is not a Rated Market Participant.

Unsecured Covered Entity is, collectively, an Unsecured Municipal Market Participant and an Unsecured Non-Municipal Covered Entity.

Unsecured Municipal Default Amount is defined in Section 3.3(i) of the ISO New England Billing Policy.

Unsecured Municipal Market Participant is defined in Section 3.3(h) of the ISO New England Billing Policy.

Unsecured Municipal Transmission Default Amount is defined in Section 3.4.f of the ISO New England Billing Policy.

Unsecured Non-Municipal Covered Entity is a Covered Entity that is not a Municipal Market Participant or a Non-Market Participant Transmission Customer and has a Market Credit Limit or Transmission Credit Limit of greater than $0 under the ISO New England Financial Assurance Policy.

Unsecured Non-Municipal Default Amount is defined in Section 3.3(i) of the ISO New England Billing Policy.

Unsecured Non-Municipal Transmission Default Amount is defined in Section 3.3(i) of the ISO New England Billing Policy.

Unsecured Transmission Default Amounts are, collectively, the Unsecured Municipal Transmission Default Amount and the Unsecured Non-Municipal Transmission Default Amount.

Unsettled FTR Financial Assurance is an amount of financial assurance required from a Designated FTR Participant as calculated pursuant to Section VI.B of the ISO New England Financial Assurance Policy.

Updated Measurement and Verification Plan is an optional Measurement and Verification Plan that may be submitted as part of a subsequent qualification process for a Forward Capacity Auction prior to the beginning of the Capacity Commitment Period of the On-Peak Demand Resource or Seasonal Peak Demand Response project. The Updated Measurement and Verification Plan may include updated project specifications, measurement and verification protocols, and performance data as described in Section III.13.1.4.3.1.2 of Market Rule 1 and the ISO New England Manuals.

VAR CC Rate is the CC rate paid to Qualified Reactive Resources for VAR Service capability under Section IV.A of Schedule 2 of the OATT.

VAR Payment is the payment made to Qualified Reactive Resources for VAR Service capability under Section IV.A of Schedule 2 of the OATT.

VAR Service is the provision of reactive power voltage support to the New England Transmission System by a Qualified Reactive Resource or by other generators that are dispatched by the ISO to provide dynamic reactive power as described in Schedule 2 of the OATT.

Virtual Cap is $2,000/MWh.

Virtual Requirements are determined in accordance with Section III.A(iv) of the ISO New England Financial Assurance Policy.

Volt Ampere Reactive (VAR) is a measurement of reactive power.

Volumetric Measure (VM) is a type of billing determinant under Schedule 2 of Section IV.A of the Tariff used to assess charges to Customers under Section IV.A of the Tariff.

Winter ARA Qualified Capacity is described in Section III.13.4.2.1.2.1.1.2 of Market Rule 1.

Winter Capability Period means one of two time periods defined by the ISO for the purposes of rating and auditing resources pursuant to Section III.9. The time period associated with the Winter Capability Period is the period October 1 through May 31.

Winter Intermittent Reliability Hours are defined in Section III.13.1.2.2.2.2(c) of Market Rule 1.

Year means a period of 365 or 366 days, whichever is appropriate, commencing on, or on the anniversary of March 1, 1997. Year One is the Year commencing on March 1, 1997, and Years Two and higher follow it in sequence.

Zonal Price is calculated in accordance with Section III.2.7 of Market Rule 1.

Zonal Capacity Obligation is calculated in accordance with Section III.13.7.5.2 of Market Rule 1.

Zonal Reserve Requirement is the combined amount of TMSR, TMNSR, and TMOR required for a Reserve Zone as described in Section III.2.7A and ISO New England Operating Procedure No. 8.

STANDARD MARKET DESIGN

III.1 Market Operations

III.1.1 Introduction.

This Market Rule 1 sets forth the scheduling, other procedures, and certain general provisions applicable to the operation of the New England Markets within the New England Control Area. The ISO shall operate the New England Markets in compliance with NERC, NPCC and ISO reliability criteria. The ISO is the Counterparty for agreements and transactions with its Customers (including assignments involving Customers), including bilateral transactions described in Market Rule 1, and sales to the ISO and/or purchases from the ISO of energy, reserves, Ancillary Services, capacity, demand/load response, FTRs and other products, paying or charging (if and as applicable) its Customers the amounts produced by the pertinent market clearing process or through the other pricing mechanisms described in Market Rule 1. The bilateral transactions to which the ISO is the Counterparty (subject to compliance with the requirements of Section III.1.4) include, but are not limited to, Internal Bilaterals for Load, Internal Bilaterals for Market for Energy, Annual Reconfiguration Transactions, Capacity Supply Obligation Bilaterals, Capacity Load Obligation Bilaterals, Capacity Performance Bilaterals, and the transactions described in Sections III.9.4.1 (internal bilateral transactions that transfer Forward Reserve Obligations), and III.13.1.6 (Self-Supplied FCA Resources). Notwithstanding the foregoing, the ISO will not act as Counterparty for the import into the New England Control Area, for the use of Publicly Owned Entities, of: (1) energy, capacity, and ancillary products associated therewith, to which the Publicly Owned Entities are given preference under Articles 407 and 408 of the project license for the New York Power Authority's Niagara Project; and (2) energy, capacity, and ancillary products associated therewith, to which Publicly Owned Entities are entitled under Article 419 of the project license for the New York Power Authority's Franklin D. Roosevelt – St. Lawrence Project. This Market Rule 1 addresses each of the three time frames pertinent to the daily operation of the New England Markets: "Pre-scheduling" as specified in Section III.1.9, "Scheduling" as specified in III.1.10, and "Dispatch" as specified in III.1.11. This Market Rule 1 became effective on February 1, 2005.

III.1.2 [Reserved.]

III.1.3 Definitions.

Whenever used in Market Rule 1, in either the singular or plural number, capitalized terms shall have the meanings specified in Section I of the Tariff. Terms used in Market Rule 1 that are not defined in Section

I shall have the meanings customarily attributed to such terms by the electric utility industry in New England or as defined elsewhere in the ISO New England Filed Documents. Terms used in Market Rule 1 that are defined in Section I are subject to the 60% Participant Vote threshold specified in Section 11.1.2 of the Participants Agreement.

III.1.3.1 [Reserved.]

III.1.3.2 [Reserved.]

III.1.3.3 [Reserved.]

III.1.4 Requirements for Certain Transactions.

III.1.4.1 ISO Settlement of Certain Transactions.

The ISO will settle, and act as Counterparty to, the transactions described in Section III.1.4.2 if the transactions (and their related transactions) conform to, and the transacting Market Participants comply with, the requirements specified in Section III.1.4.3.

III.1.4.2 Transactions Subject to Requirements of Section III.1.4.

Transactions that must conform to the requirements of Section III.1.4 include: Internal Bilaterals for Load, Internal Bilaterals for Market for Energy, Annual Reconfiguration Transactions, Capacity Supply Obligation Bilaterals, Capacity Load Obligation Bilaterals, Capacity Performance Bilaterals, and the transactions described in Sections III.9.4.1 (internal bilateral transactions that transfer Forward Reserve Obligations), and III.13.1.6 (Self-Supplied FCA Resources). The foregoing are referred to collectively as "Section III.1.4 Transactions," and individually as a "Section III.1.4 Transaction." Transactions that conform to the standards are referred to collectively as "Section III.1.4 Conforming Transactions," and individually as a "Section III.1.4 Conforming Transaction."

III.1.4.3 Requirements for Section III.1.4 Conforming Transactions.

(a) To qualify as a Section III.1.4 Conforming Transaction, a Section III.1.4 Transaction must constitute an exchange for an off-market transaction (a "Related Transaction"), where the Related Transaction:

(i) is not cleared or settled by the ISO as Counterparty;

(ii) is a spot, forward or derivatives contract that contemplates the transfer of energy or a MW obligation to or from a Market Participant;

(iii) involves commercially appropriate obligations that impose a duty to transfer electricity or a MW obligation from the seller to the buyer, or from the buyer to the seller, with performance taking place within a reasonable time in accordance with prevailing cash market practices; and

(iv) is not contingent on either party to carry out the Section III.1.4 Transaction.

(b) In addition, to qualify as a Section III.1.4 Conforming Transaction:

(i) the Section III.1.4 Transaction must be executed between separate beneficial owners or separate parties trading for independently controlled accounts;

(ii) the Section III.1.4 Transaction and the Related Transaction must be separately identified in the records of the parties to the transactions; and

(iii) the Section III.1.4 Transaction must be separately identified in the records of the ISO.

(c) As further requirements:

(i) each party to the Section III.1.4 Transaction and Related Transaction must maintain, and produce upon request of the ISO, records demonstrating compliance with the requirements of Sections III.1.4.3(a) and (b) for the Section III.1.4 Transaction, the Related Transaction and any other transaction that is directly related to, or integrated in any way with, the Related Transaction, including the identity of the counterparties and the material economic terms of the transactions including their price, tenor, quantity and execution date; and

(ii) each party to the Section III.1.4 Transaction must be a Market Participant that meets all requirements of the ISO New England Financial Assurance Policy.

III.1.5 Resource Auditing.

III.1.5.1 Claimed Capability Audits.

III.1.5.1.1 General Audit Requirements.

(a) The following types of Claimed Capability Audits may be performed:

(i) An Establish Claimed Capability Audit establishes the Generator Asset's ability to respond to ISO Dispatch Instructions and to maintain performance at a specified output level for a specified duration.

(ii) A Seasonal Claimed Capability Audit determines a Generator Asset's capability to perform under specified summer and winter conditions for a specified duration.

(iii) A Seasonal DR Audit determines the ability of a Demand Response Resource to perform during specified months for a specified duration.

(iv) An ISO-Initiated Claimed Capability Audit is conducted by the ISO to verify the Generator Asset's Establish Claimed Capability Audit value or the Demand Response Resource's Seasonal DR Audit value.

(b) The Claimed Capability Audit value of a Generator Asset shall reflect any limitations based upon the interdependence of common elements between two or more Generator Assets such as: auxiliaries, limiting operating parameters, and the deployment of operating personnel.

(c) The Claimed Capability Audit value of gas turbine, combined cycle, and pseudo-combined cycle assets shall be normalized to standard 90° (summer) and 20° (winter) temperatures.

(d) The Claimed Capability Audit value for steam turbine assets with steam exports, combined cycle, or pseudo-combined cycle assets with steam exports where steam is exported for uses external to the electric power facility, shall be normalized to the facility's Seasonal Claimed Capability steam demand.

(e) A Claimed Capability Audit may be denied or rescheduled by the ISO if its performance will jeopardize the reliable operation of the electrical system.

III.1.5.1.2 Establish Claimed Capability Audit.

(a) An Establish Claimed Capability Audit may be performed only by a Generator Asset.

(b) The time and date of an Establish Claimed Capability Audit shall be unannounced.

(c) For a newly commercial Generator Asset:

(i) An Establish Claimed Capability Audit will be scheduled by the ISO within five Business Days of the commercial operation date for all Generator Assets except:

1. Non-intermittent daily cycle hydro;
2. Non-intermittent net-metered, or special qualifying facilities that do not elect to audit as described in Section III.1.5.1.3; and
3. Intermittent Generator Assets

(ii) The Establish Claimed Capability Audit values for both summer and winter shall equal the mean net real power output demonstrated over the duration of the audit, as reflected in hourly revenue metering data, normalized for temperature and steam exports.

(iii) The Establish Claimed Capability Audit values shall be effective as of the commercial operation date of the Generator Asset.

(d) For Generator Assets with an Establish Claimed Capability Audit value:

(i) An Establish Claimed Capability Audit may be performed at the request of a Market Participant in order to support a change in the summer and winter Establish Claimed Capability Audit values for a Generator Asset.

(ii) An Establish Claimed Capability Audit shall be performed within five Business Days of the date of the request.

(iii) The Establish Claimed Capability Audit values for both summer and winter shall equal the mean net real power output demonstrated over the duration of the audit, as reflected in hourly revenue metering data, normalized for temperature and steam exports.

(iv) The Establish Claimed Capability Audit values become effective one Business Day following notification of the audit results to the Market Participant by the ISO.

(v) A Market Participant may cancel an audit request prior to issuance of the audit Dispatch Instruction.

(e) An Establish Claimed Capability Audit value may not exceed the maximum interconnected flow specified in the Network Resource Capability for the resource associated with the Generator Asset.

(f) Establish Claimed Capability Audits shall be performed on non-NERC holiday weekdays between 0800 and 2200.

(g) To conduct an Establish Claimed Capability Audit, the ISO shall:

(i) Initiate an Establish Claimed Capability Audit by issuing a Dispatch Instruction ordering the Generator Asset's net output to increase from the current operating level to its Real-Time High Operating Limit.

(ii) Indicate when issuing the Dispatch Instruction that an audit will be conducted.

(iii) Begin the audit with the first full clock hour after sufficient time has been allowed for the asset to ramp, based on its offered ramp rate from its current operating point to reach its Real-Time High Operating Limit.

(h) An Establish Claimed Capability Audit shall be performed for the following contiguous duration:

Duration Required for an Establish Claimed Capability Audit	
Type	**Claimed Capability Audit Duration (Hrs)**
Steam Turbine (Includes Nuclear)	4
Combined Cycle	4
Integrated Coal Gasification Combustion Cycle	4
Pressurized Fluidized Bed Combustion	4

Combustion Gas Turbine	1
Internal Combustion Engine	1
Hydraulic Turbine – Reversible (Electric Storage) Hydraulic Turbine – Other	2
Hydro-Conventional Daily Pondage Hydro-Conventional Run of River Hydro-Conventional Weekly	2
Wind Photovoltaic Fuel Cell	2
Other Electric Storage (Excludes Hydraulic Turbine - Reversible)	2

(i) The ISO, in consultation with the Market Participant, will determine the contiguous audit duration for a Generator Asset of a type not listed in Section III.1.5.1.2(h).

III.1.5.1.3. Seasonal Claimed Capability Audits.

(a) A Seasonal Claimed Capability Audit may be performed only by a Generator Asset.

(b) A Seasonal Claimed Capability Audit must be conducted by all Generator Assets except:

(i) Non-intermittent daily hydro; and

(ii) Intermittent, net-metered, and special qualifying facilities. Non-intermittent net-metered and special qualifying facilities may elect to perform Seasonal Claimed Capability Audits pursuant to Section III.1.7.11(c)(iv).

(c) An Establish Claimed Capability Audit or ISO-Initiated Claimed Capability Audit that meets the requirements of a Seasonal Claimed Capability Audit in this Section III.1.5.1.3 may be used to fulfill a Generator Asset's Seasonal Claimed Capability Audit obligation.

(d) Except as provided in Section III.1.5.1.3(n) below, a summer Seasonal Claimed Capability Audit must be conducted:

(i) At least once every Capability Demonstration Year;

(ii) Either (1) at a mean ambient temperature during the audit that is greater than or equal to 80 degrees Fahrenheit at the location of the Generator Asset, or (2) during an ISO-announced summer Seasonal Claimed Capability Audit window.

(e) A winter Seasonal Claimed Capability Audit must be conducted:

(i) At least once in the previous three Capability Demonstration Years, except that a newly commercial Generator Asset which becomes commercial on or after:

(1) September 1 and prior to December 31 shall perform a winter Seasonal Claimed Capability Audit prior to the end of that Capability Demonstration Year.

(2) January 1 shall perform a winter Seasonal Claimed Capability Audit prior to the end of the next Capability Demonstration Year.

(ii) Either (1) at a mean ambient temperature during the audit that is less than or equal to 32 degrees Fahrenheit at the location of the Generator Asset, or (2) during an ISO-announced winter Seasonal Claimed Capability Audit window.

(f) A Seasonal Claimed Capability Audit shall be performed by operating the Generator Asset for the audit time period and submitting to the ISO operational data that meets the following requirements:

(i) The Market Participant must notify the ISO of its request to use the dispatch to satisfy the Seasonal Claimed Capability Audit requirement by 5:00 p.m. on the fifth Business Day following the day on which the audit concludes.

(ii) The notification must include the date and time period of the demonstration to be used for the Seasonal Claimed Capability Audit and other relevant operating data.

(g) The Seasonal Claimed Capability Audit value (summer or winter) will be the mean net real power output demonstrated over the duration of the audit, as reflected in hourly revenue metering data, normalized for temperature and steam exports.

(h) The Seasonal Claimed Capability Audit value (summer or winter) shall be the most recent audit data submitted to the ISO meeting the requirements of this Section III.1.5.1.3. In the event that a Market Participant fails to submit Seasonal Claimed Capability Audit data to meet the timing requirements in Section III.1.5.1.3(d) and (e), the Seasonal Claimed Capability Audit value for the season shall be set to zero.

(i) The Seasonal Claimed Capability Audit value shall become effective one Business Day following notification of the audit results to the Market Participant by the ISO.

(j) A Seasonal Claimed Capability Audit shall be performed for the following contiguous duration:

Duration Required for a Seasonal Claimed Capability Audit	
Type	**Claimed Capability Audit Duration (Hrs)**
Steam Turbine (Includes Nuclear)	2
Combined Cycle	2

Integrated Coal Gasification Combustion Cycle	2
Pressurized Fluidized Bed Combustion	2
Combustion Gas Turbine	1
Internal Combustion Engine	1
Hydraulic Turbine-Reversible (Electric Storage) Hydraulic Turbine-Other	2
Hydro-Conventional Weekly	2
Fuel Cell	1
Other Electric Storage (Excludes Hydraulic Turbine - Reversible)	2

(k) A Generator Asset that is on a planned outage that was approved in the ISO's annual maintenance scheduling process during all hours that meet the temperature requirements for a Seasonal Claimed Capability Audit that is to be performed by the asset during that Capability Demonstration Year shall:

(i) Submit to the ISO, prior to September 10, an explanation of the circumstances rendering it incapable of meeting these auditing requirements;

(ii) Have its Seasonal Claimed Capability Audit value for the season set to zero; and

(iii) Perform the required Seasonal Claimed Capability Audit on the next available day that meets the Seasonal Claimed Capability Audit temperature requirements.

(l) A Generator Asset that does not meet the auditing requirements of this Section III.1.5.1.3 because (1) every time the temperature requirements were met at the Generator Asset's location the ISO denied the request to operate to full capability, or (2) the temperature requirements were not met at the Generator Asset's location during the Capability Demonstration Year during which the asset was required to perform a Seasonal Claimed Capability Audit during the hours 0700 to 2300 for each weekday excluding those weekdays that are defined as NERC holidays, shall:

(i) Submit to the ISO, prior to September 10, an explanation of the circumstances rendering it incapable of meeting these temperature requirements, including verifiable temperature data;

(ii) Retain the current Seasonal Claimed Capability Audit value for the season; and

(iii) Perform the required Seasonal Claimed Capability Audit during the next Capability Demonstration Year.

(m) The ISO may issue notice of a summer or winter Seasonal Claimed Capability Audit window for some or all of the New England Control Area if the ISO determines that weather forecasts indicate that temperatures during the audit window will meet the summer or winter Seasonal

Claimed Capability Audit temperature requirements. A notice shall be issued at least 48 hours prior to the opening of the audit window. Any audit performed during the announced audit window shall be deemed to meet the temperature requirement for the summer or winter audit. In the event that five or more audit windows for the summer Seasonal Claimed Capability Audit temperature requirement, each of at least a four hour duration between 0700 and 2300 and occurring on a weekday excluding those weekdays that are defined as NERC holidays, are not opened for a Generator Asset prior to August 15 during a Capability Demonstration Year, a two-week audit window shall be opened for that Generator Asset to perform a summer Seasonal Claimed Capability Audit, and any audit performed by that Generator Asset during the open audit window shall be deemed to meet the temperature requirement for the summer Seasonal Claimed Capability Audit. The open audit window shall be between 0700 and 2300 each day during August 15 through August 31.

(n) A Market Participant that is required to perform testing on a Generator Asset that is in addition to a summer Seasonal Claimed Capability Audit may notify the ISO that the summer Seasonal Claimed Capability Audit was performed in conjunction with this additional testing, provided that:

(i) The notification shall be provided at the time the Seasonal Claimed Capability Audit data is submitted under Section III.1.5.1.3(f).

(ii) The notification explains the nature of the additional testing and that the summer Seasonal Claimed Capability Audit was performed while the Generator Asset was online to perform this additional testing.

(iii) The summer Seasonal Claimed Capability Audit and additional testing are performed during the months of June, July or August between the hours of 0700 and 2300.

(iv) In the event that the summer Seasonal Claimed Capability Audit does not meet the temperature requirements of Section III.1.5.1.3(d)(ii), the summer Seasonal Claimed Capability Audit value may not exceed the summer Seasonal Claimed Capability Audit value from the prior Capability Demonstration Year.

(v) This Section III.1.5.1.3(n) may be utilized no more frequently than once every three Capability Demonstration Years for a Generator Asset.

(o) The ISO, in consultation with the Market Participant, will determine the contiguous audit duration for a Generator Asset of a type not listed in Section III.1.5.1.3(j).

III.1.5.1.3.1 Seasonal DR Audits.

(a) A Seasonal DR Audit may be performed only by a Demand Response Resource.

(b) A Seasonal DR Audit shall be performed for 12 contiguous five-minute intervals.

(c) A summer Seasonal DR Audit must be conducted by all Demand Response Resources:

(i) At least once every Capability Demonstration Year;

(ii) During the months of April through November;

(d) A winter Seasonal DR Audit must be conducted by all Demand Response Resources:

(i) At least once every Capability Demonstration Year;

(ii) During the months of December through March.

(e) A Seasonal DR Audit may be performed either:

(i) At the request of a Market Participant as described in subsection (f) below; or

(ii) By the Market Participant designating a period of dispatch after the fact as described in subsection (g) below.

(f) If a Market Participant requests a Seasonal DR Audit:

(i) The ISO shall perform the Seasonal DR Audit at an unannounced time between 0800 and 2200 on non-NERC holiday weekdays within five Business Days of the date of the request.

(ii) The ISO shall initiate the Seasonal DR Audit by issuing a Dispatch Instruction ordering the Demand Response Resource to its Maximum Reduction.

(iii) The ISO shall indicate when issuing the Dispatch Instruction that an audit will be conducted.

(iv) The ISO shall begin the audit with the start of the first five-minute interval after sufficient time has been allowed for the resource to ramp, based on its Demand Reduction Offer parameters, to its Maximum Reduction.

(v) A Market Participant may cancel an audit request prior to issuance of the audit Dispatch Instruction.

(g) If the Seasonal DR Audit is performed by the designation of a period of dispatch after the fact, the designated period must meet all of the requirements in this Section III.1.5.1.3.1 and:

(i) The Market Participant must notify the ISO of its request to use the dispatch to satisfy the Seasonal DR Audit requirement by 5:00 p.m. on the fifth Business Day following the day on which the audit concludes.

(ii) The notification must include the date and time period of the demonstration to be used for the Seasonal DR Audit.

(iii) The demonstration period may begin with the start of any five-minute interval after the completion of the Demand Response Resource Notification Time.

(iv) A CLAIM10 audit or CLAIM30 audit that meets the requirements of a Seasonal DR Audit as provided in this Section III.1.5.1.3.1 may be used to fulfill the Seasonal DR Audit obligation of a Demand Response Resource.

(h) An ISO-Initiated Claimed Capability Audit fulfils the Seasonal DR Audit obligation of a Demand Response Resource.

(i) Each Demand Response Asset associated with a Demand Response Resource is evaluated during the Seasonal DR Audit of the Demand Response Resource.

(j) Any Demand Response Asset on a forced or scheduled curtailment as defined in Section III.8.3 is assessed a zero audit value.

(k) The Seasonal DR Audit value (summer or winter) of a Demand Response Resource resulting from the Seasonal DR Audit shall be the sum of the average demand reductions demonstrated during the audit by each of the Demand Response Resource's constituent Demand Response Assets.

(l) If a Demand Response Asset is added to or removed from a Demand Response Resource between audits, the Demand Response Resource's capability shall be updated to reflect the inclusion or exclusion of the audit value of the Demand Response Asset, such that at any point in time the summer or winter Seasonal DR Audit value of a Demand Response Resource shall equal the sum of the most recent valid like-season audit values of its constituent Demand Response Assets.

(m) The Seasonal DR Audit value shall become effective one calendar day following notification of the audit results to the Market Participant by the ISO.

(n) The summer or winter audit value of a Demand Response Asset shall be set to zero at the end of the Capability Demonstration Year if the Demand Response Asset did not perform a Seasonal DR Audit for that season as part of a Demand Response Resource during that Capability Demonstration Year.

(o) For a Demand Response Asset that was associated with a "Real-Time Demand Response Resource" or a "Real-Time Emergency Generation Resource," as those terms were defined prior to June 1, 2018, any valid result from an audit conducted prior to June 1, 2018 shall continue to be valid on June 1, 2018, and shall retain the same expiration date.

III.1.5.1.4. ISO-Initiated Claimed Capability Audits.

(a) An ISO-Initiated Claimed Capability Audit may be performed by the ISO at any time.

(b) An ISO-Initiated Claimed Capability Audit value shall replace either the summer or winter Seasonal DR Audit value for a Demand Response Resource and shall replace both the winter and summer Establish Claimed Capability Audit values for a Generator Asset, normalized for temperature and steam exports, except:

(i) The Establish Claimed Capability Audit values for a Generator Asset may not exceed the maximum interconnected flow specified in the Network Resource Capability for that resource.

(ii) An ISO-Initiated Claimed Capability Audit value for a Generator Asset shall not set the winter Establish Claimed Capability Audit value unless the ISO-Initiated Claimed Capability Audit was performed at a mean ambient temperature that is less than or equal to 32 degrees Fahrenheit at the Generator Asset location.

(c) If for a Generator Asset a Market Participant submits pressure and relative humidity data for the previous Establish Claimed Capability Audit and the current ISO-Initiated Claimed Capability Audit, the Establish Claimed Capability Audit values derived from the ISO-Initiated Claimed Capability Audit will be normalized to the pressure of the previous Establish Claimed Capability Audit and a relative humidity of 64%.

(d) The audit values derived from the ISO-Initiated Claimed Capability Audit shall become effective one Business Day following notification of the audit results to the Market Participant by the ISO.

(e) To conduct an ISO-Initiated Claimed Capability Audit, the ISO shall:

(i) Initiate an ISO-Initiated Claimed Capability Audit by issuing a Dispatch Instruction ordering the Generator Asset to its Real-Time High Operating Limit or the Demand Response Resource to its Maximum Reduction.

(ii) Indicate when issuing the Dispatch Instruction that an audit will be conducted.

(iii) For Generator Assets, begin the audit with the first full clock hour after sufficient time has been allowed for the Generator Asset to ramp, based on its offered ramp rate, from its current operating point to its Real-Time High Operating Limit.

(iv) For Demand Response Resources, begin the audit with the first five-minute interval after sufficient time has been allowed for the resource to ramp, based on its Demand Reduction Offer parameters, to its Maximum Reduction.

(f) An ISO-Initiated Claimed Capability Audit shall be performed for the following contiguous duration:

Duration Required for an ISO-Initiated Claimed Capability Audit	
Type	**Claimed Capability Audit Duration (Hrs)**
Steam Turbine (Includes Nuclear)	4
Combined Cycle	4

Integrated Coal Gasification Combustion Cycle	4
Pressurized Fluidized Bed Combustion	4
Combustion Gas Turbine	1
Internal Combustion Engine	1
Hydraulic Turbine – Reversible (Electric Storage) Hydraulic Turbine – Other	2
Hydro-Conventional Daily Pondage Hydro-Conventional Run of River Hydro-Conventional Weekly	2
Wind Photovoltaic Fuel Cell	2
Other Electric Storage (Excludes Hydraulic Turbine – Reversible)	2
Demand Response Resource	1

(g) The ISO, in consultation with the Market Participant, will determine the contiguous audit duration for an Asset or Resource type not listed in Section III.1.5.1.4(f).

III.1.5.2 ISO-Initiated Parameter Auditing.

(a) The ISO may perform an audit of any Supply Offer, Demand Reduction Offer or other operating parameter that impacts the ability of a Generator Asset or Demand Response Resource to provide real-time energy or reserves.

(b) Generator audits shall be performed using the following methods for the relevant parameter:

(i) **Economic Maximum Limit**. The Generator Asset shall be evaluated based upon its ability to achieve the current offered Economic Maximum Limit value, through a review of historical dispatch data or based on a response to a current ISO-issued Dispatch Instruction.

(ii) **Manual Response Rate**. The Generator Asset shall be evaluated based upon its ability to respond to Dispatch Instructions at its offered Manual Response Rate, including hold points and changes in Manual Response Rates.

(iii) **Start-Up Time**. The Generator Asset shall be evaluated based upon its ability to achieve the offered Start-Up Time.

(iv) **Notification Time**. The Generator Asset shall be evaluated based upon its ability to close its output breaker within its offered Notification Time.

(v) **CLAIM10**. The Generator Asset shall be evaluated based upon its ability to reach its CLAIM10 in accordance with Section III.9.5.

(vi) **CLAIM30**. The Generator Asset shall be evaluated based upon its ability to reach its CLAIM30 in accordance with Section III.9.5.

(vii) **Automatic Response Rate**. The Generator Asset shall be analyzed, based upon a review of historical performance data, for its ability to respond to four-second electronic Dispatch Instructions.

(viii) **Dual Fuel Capability**. A Generator Asset that is capable of operating on multiple fuels may be required to audit on a specific fuel, as set out in Section III.1.5.2(f).

(c) Demand Response Resource audits shall be performed using the following methods:

(i) **Maximum Reduction**. The Demand Response Resource shall be evaluated based upon its ability to achieve the current offered Maximum Reduction value, through a review of historical dispatch data or based on a response to a current Dispatch Instruction.

(ii) **Demand Response Resource Ramp Rate**. The Demand Response Resource shall be evaluated based upon its ability to respond to Dispatch Instructions at its offered Demand Response Resource Ramp Rate.

(iii) **Demand Response Resource Start-Up Time**. The Demand Response Resource shall be evaluated based upon its ability to achieve its Minimum Reduction within the offered Demand Response Resource Start-Up Time, in response to a Dispatch Instruction and after completing its Demand Response Resource Notification Time.

(iv) **Demand Response Resource Notification Time**. The Demand Response Resource shall be evaluated based upon its ability to start reducing demand within its offered Demand Response Resource Notification Time, from the receipt of a Dispatch Instruction when the Demand Response Resource was not previously reducing demand.

(v) **CLAIM10**. The Demand Response Resource shall be evaluated based upon its ability to reach its CLAIM10 in accordance with Section III.9.5.

(vi) **CLAIM30**. The Demand Response Resource shall be evaluated based upon its ability to reach its CLAIM30 in accordance with Section III.9.5.

(d) To conduct an audit based upon historical data, the ISO shall:

(i) Obtain data through random sampling of generator or Demand Response Resource performance in response to Dispatch Instructions; or

(ii) Obtain data through continual monitoring of generator or Demand Response Resource performance in response to Dispatch Instructions.

(e) To conduct an unannounced audit, the ISO shall initiate the audit by issuing a Dispatch Instruction ordering the Generator Asset or Demand Response Resource to change from the current operating level to a level that permits the ISO to evaluate the performance of the Generator Asset or Demand Response Resource for the parameters being audited.

(f) To conduct an audit of the capability of a Generator Asset described in Section III.1.5.2(b)(viii) to run on a specific fuel:

(i) The ISO shall notify the Lead Market Participant if a Generator Asset is required to undergo an audit on a specific fuel. The ISO, in consultation with the Lead Market Participant, shall develop a plan for the audit.

(ii) The Lead Market Participant will have the ability to propose the time and date of the audit within the ISO's prescribed time frame and must notify the ISO at least five Business Days in advance of the audit, unless otherwise agreed to by the ISO and the Lead Market Participant.

(g) To the extent that the audit results indicate a Market Participant is providing Supply Offer, Demand Reduction Offer or other operating parameter values that are not representative of the actual capability of the Generator Asset or Demand Response Resource, the values for the Generator Asset or Demand Response Resource shall be restricted to those values that are supported by the audit.

(h) In the event that a Generator Asset or Demand Response Resource has had a parameter value restricted:

(i) The Market Participant may submit a restoration plan to the ISO to restore that parameter. The restoration plan shall:

1. Provide an explanation of the discrepancy;
2. Indicate the steps that the Market Participant will take to re-establish the parameter's value;
3. Indicate the timeline for completing the restoration; and
4. Explain the testing that the Market Participant will undertake to verify restoration of the parameter value upon completion.

(ii) The ISO shall:

1. Accept the restoration plan if implementation of the plan, including the testing plan, is reasonably likely to support the proposed change in the parameter value restriction;
2. Coordinate with the Market Participant to perform required testing upon completion of the restoration; and
3. Modify the parameter value restriction following completion of the restoration plan, based upon tested values.

III.1.5.3 Reactive Capability Audits.

(a) Two types of Reactive Capability Audits may be performed:

(i) A lagging Reactive Capability Audit, which is an audit that measures a Reactive Resource's ability to provide reactive power to the transmission system at a specified real power output or consumption.

(ii) A leading Reactive Capability Audit, which is an audit that measures a Reactive Resource's ability to absorb reactive power from the transmission system at a specified real power output or consumption.

(b) The ISO shall develop a list of Reactive Resources that must conduct Reactive Capability Audits. The list shall include Reactive Resources that: (i) have a gross individual nameplate rating greater than 20 MVA; (ii) are directly connected, or are connected through equipment designed primarily for delivering real or reactive power to an interconnection point, to the transmission system at a voltage of 100 kV or above; and (iii) are not exempted from providing voltage control by the ISO. Additional criteria to be used in adding a Reactive Resource to the list includes, but is not limited to, the effect of the Reactive Resource on System Operating Limits, Interconnection Reliability Operating Limits, and local area voltage limits during the following operating states: normal, emergency, and system restoration.

(c) Unless otherwise directed by the ISO, Reactive Resources that are required to perform Reactive Capability Audits shall perform both a lagging Reactive Capability Audit and a leading Reactive Capability Audit.

(d) All Reactive Capability Audits shall meet the testing conditions specified in the ISO New England Operating Documents.

(e) The Reactive Capability Audit value of a Reactive Resource shall reflect any limitations based upon the interdependence of common elements between two or more Reactive Resources such as: auxiliaries, limiting operating parameters, and the deployment of operating personnel.

(f) A Reactive Capability Audit may be denied or rescheduled by the ISO if conducting the Reactive Capability Audit could jeopardize the reliable operation of the electrical system.

(g) Reactive Capability Audits shall be conducted at least every five years, unless otherwise required by the ISO. The ISO may require a Reactive Resource to conduct Reactive Capability Audits more often than every five years if:

(i) there is a change in the Reactive Resource that may affect the reactive power capability of the Reactive Resource;

(ii) there is a change in electrical system conditions that may affect the achievable reactive power output or absorption of the Reactive Resource; or

(iii) historical data shows that the amount of reactive power that the Reactive Resource can provide to or absorb from the transmission system is higher or lower than the latest audit data.

(h) A Lead Market Participant or Transmission Owner may request a waiver of the requirement to conduct a Reactive Capability Audit for its Reactive Resource. The ISO, at its sole discretion, shall determine whether and for how long a waiver may be granted.

III.1.6 [Reserved.]

III.1.6.1 [Reserved.]

III.1.6.2 [Reserved.]

III.1.6.3 [Reserved.]

III.1.6.4 ISO New England Manuals and ISO New England Administrative Procedures.

The ISO shall prepare, maintain and update the ISO New England Manuals and ISO New England Administrative Procedures consistent with the ISO New England Filed Documents. The ISO New England Manuals and ISO New England Administrative Procedures shall be available for inspection by the Market Participants, regulatory authorities with jurisdiction over the ISO or any Market Participant, and the public.

III.1.7 General.

III.1.7.1 Provision of Market Data to the Commission.

The ISO will electronically deliver to the Commission, on an ongoing basis and in a form and manner consistent with its collection of data and in a form and manner acceptable to the Commission, data related to the markets that it administers, in accordance with the Commission's regulations.

III.1.7.2 [Reserved.]

III.1.7.3 Agents.

A Market Participant may participate in the New England Markets through an agent, provided that such Market Participant informs the ISO in advance in writing of the appointment of such agent. A Market Participant using an agent shall be bound by all of the acts or representations of such agent with respect to transactions in the New England Markets, and shall ensure that any such agent complies with the

requirements of the ISO New England Manuals and ISO New England Administrative Procedures and the ISO New England Filed Documents.

III.1.7.4 [Reserved.]

III.1.7.5 Transmission Constraint Penalty Factors.

In the Day-Ahead Energy Market, the Transmission Constraint Penalty Factor for an interface constraint is $10,000/MWh and the Transmission Constraint Penalty Factor for all other transmission constraints is $30,000/MWh. In the Real-Time Energy Market, the Transmission Constraint Penalty Factor for any transmission constraint is $30,000/MWh. Transmission Constraint Penalty Factors are not used in calculating Locational Marginal Prices.

III.1.7.6 Scheduling and Dispatching.

(a) The ISO shall schedule Day-Ahead and schedule and dispatch in Real-Time Resources economically on the basis of least-cost, security-constrained dispatch and the prices and operating characteristics offered by Market Participants. The ISO shall schedule and dispatch sufficient Resources of the Market Participants to serve the New England Markets energy purchase requirements under normal system conditions of the Market Participants and meet the requirements of the New England Control Area for ancillary services provided by such Resources. The ISO shall use a joint optimization process to serve Real-Time Energy Market energy requirements and meet Real-Time Operating Reserve requirements based on a least-cost, security-constrained economic dispatch. Commencing on June 1, 2024, the ISO shall use a joint optimization process to serve Day-Ahead Energy Market energy requirements and Day-Ahead Ancillary Services requirements based on a security-constrained economic commitment and dispatch.

(b) In the event that one or more Resources cannot be scheduled in the Day-Ahead Energy Market on the basis of a least-cost, security-constrained economic commitment and dispatch as a result of one or more Self-Schedule offers contributing to a transmission limit violation, the following scheduling protocols will apply:

(i) When a single Self-Schedule offer contributes to a transmission limit violation, the Self-Schedule offer will not be scheduled for the entire Self-Schedule period in development of Day-Ahead schedules.

(ii) When two Self-Schedule offers contribute to a transmission limit violation, parallel clearing solutions will be executed such that, for each solution, one of the Self-Schedule offers will be omitted for its entire Self-Schedule period. The least cost solution will be used for purposes of determining which Resources are scheduled in the Day-Ahead Energy Market.

(iii) When three or more Self-Schedule offers contribute to a transmission limit violation, the ISO will determine the total daily MWh for each Self-Schedule offer and will omit Self-Schedule offers in their entirety, in sequence from the offer with the least total daily MWh to the offer with the greatest total MWh, stopping when the transmission limit violation is resolved.

(c) Scheduling and dispatch shall be conducted in accordance with the ISO New England Filed Documents.

(d) The ISO shall undertake, together with Market Participants, to identify any conflict or incompatibility between the scheduling or other deadlines or specifications applicable to the New England Markets, and any relevant procedures of another Control Area, or any tariff (including the Transmission, Markets and Services Tariff). Upon determining that any such conflict or incompatibility exists, the ISO shall propose tariff or procedural changes, or undertake such other efforts as may be appropriate, to resolve any such conflict or incompatibility.

III.1.7.7 Energy Pricing.

The price paid for energy, including demand reductions, bought and sold by the ISO in the New England Markets will reflect the Locational Marginal Price at each Location, determined by the ISO in accordance with the ISO New England Filed Documents. Congestion Costs, which shall be determined by differences in the Congestion Component of Locational Marginal Prices caused by constraints, shall be calculated and collected, and the resulting revenues disbursed, by the ISO in accordance with this Market Rule 1. Loss costs associated with Pool Transmission Facilities, which shall be determined by the differences in Loss Components of the Locational Marginal Prices shall be calculated and collected, and the resulting revenues disbursed, by the ISO in accordance with this Market Rule 1.

III.1.7.8 Market Participant Resources.

A Market Participant may elect to Self-Schedule its Resources in accordance with and subject to the limitations and procedures specified in this Market Rule 1 and the ISO New England Manuals.

III.1.7.8A Day-Ahead Ancillary Services Prices.

The prices paid by the ISO for the provision of Day-Ahead Ancillary Services in the New England Markets will reflect Day-Ahead Ancillary Services clearing prices determined by the ISO in accordance with the ISO New England Filed Documents.

III.1.7.9 Real-Time Reserve Prices.

The price paid by the ISO for the provision of Real-Time Operating Reserve in the New England Markets will reflect Real-Time Reserve Clearing Prices determined by the ISO in accordance with the ISO New England Filed Documents for the system and each Reserve Zone.

III.1.7.10 Other Transactions.

Market Participants may enter into internal bilateral transactions and External Transactions for the purchase or sale of energy or other products to or from each other or any other entity, subject to the obligations of Market Participants to make resources with a Capacity Supply Obligation available for dispatch by the ISO. External Transactions that contemplate the physical transfer of energy or obligations to or from a Market Participant shall be reported to and coordinated with the ISO in accordance with this Market Rule 1 and the ISO New England Manuals.

III.1.7.11 Seasonal Claimed Capability of a Generating Capacity Resource.

(a) A Seasonal Claimed Capability value must be established and maintained for all Generating Capacity Resources. A summer Seasonal Claimed Capability is established for use from June 1 through September 30 and a winter Seasonal Claimed Capability is established for use from October 1 through May 31.

(b) The Seasonal Claimed Capability of a Generating Capacity Resource is the sum of the Seasonal Claimed Capabilities of the Generator Assets that are associated with the Generating Capacity Resource.

(c) The Seasonal Claimed Capability of a Generator Asset is:

(i) Based upon review of historical data for non-intermittent daily cycle hydro.

(ii) The median net real power output during reliability hours, as described in Section III.13.1.2.2.2, for (1) intermittent facilities, and (2) net-metered and special qualifying facilities that do not elect to audit, as reflected in hourly revenue metering data.

(iii) For non-intermittent net-metered and special qualifying facilities that elect to audit, the minimum of (1) the Generator Asset's current Seasonal Claimed Capability Audit value, as performed

pursuant to Section III.1.5.1.3; (2) the Generator Asset's current Establish Claimed Capability Audit value; and (3) the median hourly availability during hours ending 2:00 p.m. through 6:00 p.m. each day of the preceding June through September for Summer and hours ending 6:00 p.m. and 7:00 p.m. each day of the preceding October through May for Winter. The hourly availability:

a. For a Generator Asset that is available for commitment and following Dispatch Instructions, shall be the asset's Economic Maximum Limit, as submitted or redeclared.
b. For a Generator Asset that is off-line and not available for commitment shall be zero.
c. For a Generator Asset that is on-line but not able to follow Dispatch Instructions, shall be the asset's metered output.

(iv) For all other Generator Assets, the minimum of: (1) the Generator Asset's current Establish Claimed Capability Audit value and (2) the Generator Asset's current Seasonal Claimed Capability Audit value, as performed pursuant to Section III.1.5.1.3.

III.1.7.12 Seasonal DR Audit Value of an Active Demand Capacity Resource.

(a) A Seasonal DR Audit value must be established and maintained for all Active Demand Capacity Resources. A summer Seasonal DR Audit value is established for use from April 1 through November 30 and a winter Seasonal DR Audit value is established for use from December 1 through March 31.

(b) The Seasonal DR Audit value of an Active Demand Capacity Resource is the sum of the Seasonal DR Audit values of the Demand Response Resources that are associated with the Active Demand Capacity Resource.

III.1.7.13 [Reserved.]

III.1.7.14 [Reserved.]

III.1.7.15 [Reserved.]

III.1.7.16 [Reserved.]

III.1.7.17 Operating Reserve.

The ISO shall endeavor to procure and maintain an amount of Operating Reserve in Real-Time equal to the system and zonal Operating Reserve requirements as specified in the ISO New England Manuals and ISO New England Administrative Procedures. Reserve requirements for the Forward Reserve Market are determined in accordance with the methodology specified in Section III.9.2 of Market Rule 1. Operating

Reserve requirements for Real-Time dispatch within an Operating Day are determined in accordance with Market Rule 1 and ISO New England Operating Procedure No. 8, Operating Reserve and Regulation.

III.1.7.18 Ramping.

A Generator Asset, Dispatchable Asset Related Demand, or Demand Response Resource dispatched by the ISO pursuant to a control signal appropriate to increase or decrease the Resource's megawatt output, consumption, or demand reduction level shall be able to change output, consumption, or demand reduction at the ramping rate specified in the Offer Data submitted to the ISO for that Resource and shall be subject to sanctions for failure to comply as described in **Appendix B**.

III.1.7.19 Real-Time Reserve Designation.

The ISO shall determine the Real-Time Reserve Designation for each eligible Resource in accordance with this Section III.1.7.19. The Real-Time Reserve Designation shall consist of a MW value, in no case less than zero, for each Operating Reserve product: Ten-Minute Spinning Reserve, Ten-Minute Non-Spinning Reserve, and Thirty-Minute Operating Reserve.

III.1.7.19.1 Eligibility.

To be eligible to receive a Real-Time Reserve Designation, a Resource must meet all of the criteria enumerated in this Section III.1.7.19.1. A Resource that does not meet all of these criteria is not eligible to provide Operating Reserve and will not receive a Real-Time Reserve Designation.

(1) The Resource must be a Dispatchable Resource located within the metered boundaries of the New England Control Area and capable of receiving and responding to electronic Dispatch Instructions.

(2) The Resource must not be part of the first contingency supply loss.

(3) The Resource must not be designated as constrained by transmission limitations.

(4) The Resource's Operating Reserve, if activated, must be sustainable for at least one hour from the time of activation. (This eligibility requirement does not affect a Resource's obligation to follow Dispatch Instructions, even after one hour from the time of activation.)

(5) The Resource must comply with the applicable standards and requirements for provision and dispatch of Operating Reserve as specified in the ISO New England Manuals and ISO New England Administrative Procedures.

III.1.7.19.2 Calculation of Real-Time Reserve Designation.

III.1.7.19.2.1 Generator Assets.

III.1.7.19.2.1.1 On-line Generator Assets.

The Manual Response Rate used in calculations in this section shall be the lesser of the Generator Asset's offered Manual Response Rate and its audited Manual Response Rate as described in Section III.1.5.2.

(a) **Ten-Minute Spinning Reserve.** For an on-line Generator Asset (other than one registered as being composed of multiple generating units whose synchronized capability cannot be determined by the ISO), Ten-Minute Spinning Reserve shall be calculated as the increase in output the Generator Asset could achieve, relative to its current telemetered output, within ten minutes given its Manual Response Rate (and in no case to a level greater than its Economic Maximum Limit). For an on-line Generator Asset registered as being composed of multiple generating units whose synchronized capability cannot be determined by the ISO, Ten-Minute Spinning Reserve shall be zero.

(b) **Ten-Minute Non-Spinning Reserve.** For an on-line Generator Asset (other than one registered as being composed of multiple generating units whose synchronized capability cannot be determined by the ISO), Ten-Minute Non-Spinning Reserve shall be zero. For an on-line Generator Asset registered as being composed of multiple generating units whose synchronized capability cannot be determined by the ISO, Ten-Minute Non-Spinning Reserve shall be calculated as the increase in output the Generator Asset could achieve, relative to its current telemetered output, within ten minutes given its Manual Response Rate (and in no case to a level greater than its Economic Maximum Limit).

(c) **Thirty-Minute Operating Reserve.** For an on-line Generator Asset, Thirty-Minute Operating Reserve shall be calculated as the increase in output the Generator Asset could achieve, relative to its current telemetered output, within thirty minutes given its Manual Response Rate (and in no case greater than its Economic Maximum Limit) minus the Ten-Minute Spinning Reserve quantity calculated for the Generator Asset pursuant to subsection (a) above and the Ten-Minute Non-Spinning Reserve quantity calculated for the Generator Asset pursuant to subsection (b) above.

III.1.7.19.2.1.2 Off-line Generator Assets.

For an off-line Generator Asset that is not a Fast Start Generator, all components of the Real-Time Reserve Designation shall be zero.

(a) **Ten-Minute Spinning Reserve.** For an off-line Fast Start Generator, Ten-Minute Spinning Reserve shall be zero.

(b) **Ten-Minute Non-Spinning Reserve.** For an off-line Fast Start Generator, Ten-Minute Non-Spinning Reserve shall be calculated as the minimum of the Fast Start Generator's Offered CLAIM10, its CLAIM10, and its Economic Maximum Limit (provided, however, that during the Fast Start Generator's Minimum Down Time, the Fast Start Generator's Ten-Minute Non-Spinning Reserve shall be zero, except during the last ten minutes of its Minimum Down Time, at which time the ISO will prorate the Fast Start Generator's Ten-Minute Non-Spinning Reserve to account for the remaining amount of time until the Fast Start Generator's Minimum Down Time expires).

(c) **Thirty-Minute Operating Reserve.** For an off-line Fast Start Generator, Thirty-Minute Operating Reserve shall be calculated as: (i) the minimum of the Fast Start Generator's Offered CLAIM30, its CLAIM30, and its Economic Maximum Limit (provided, however, that during the Fast Start Generator's Minimum Down Time, the Fast Start Generator's Thirty-Minute Operating Reserve shall be zero, except during the last thirty minutes of its Minimum Down Time, at which time the ISO will prorate the Fast Start Generator's Thirty-Minute Operating Reserve to account for the remaining amount of time until the Fast Start Generator's Minimum Down Time expires), minus (ii) the Ten-Minute Non-Spinning Reserve quantity calculated for the Fast Start Generator pursuant to subsection (b) above.

III.1.7.19.2.2 Dispatchable Asset Related Demand.

III.1.7.19.2.2.1 Storage DARDs.

(a) **Ten-Minute Spinning Reserve.** For a Storage DARD, Ten-Minute Spinning Reserve shall be calculated as the absolute value of the amount of current telemetered consumption.

(b) **Ten-Minute Non-Spinning Reserve.** For a Storage DARD, Ten-Minute Non-Spinning Reserve shall be zero.

(c) **Thirty-Minute Operating Reserve.** For a Storage DARD, Thirty-Minute Operating Reserve shall be zero.

III.1.7.19.2.2.2 Dispatchable Asset Related Demand Other Than Storage DARDs.

(a) **Ten-Minute Spinning Reserve.** For a Dispatchable Asset Related Demand (other than a Storage DARD) that has no Controllable Behind-the-Meter Generation, Ten-Minute Spinning Reserve shall be calculated as the decrease in consumption that the Dispatchable Asset Related Demand could achieve, relative to its current telemetered consumption, within ten minutes given its ramp rate (and in no case to an amount less than its Minimum Consumption Limit). For a Dispatchable Asset Related Demand (other than a Storage DARD) having Controllable Behind-the-Meter Generation, Ten-Minute Spinning Reserve shall be zero.

(b) **Ten-Minute Non-Spinning Reserve.** For a Dispatchable Asset Related Demand (other than a Storage DARD) that has no Controllable Behind-the-Meter Generation, Ten-Minute Non-Spinning Reserve shall be zero. For a Dispatchable Asset Related Demand (other than a Storage DARD) having Controllable Behind-the-Meter Generation, Ten-Minute Non-Spinning Reserve shall be calculated as the decrease in consumption that the Dispatchable Asset Related Demand could achieve, relative to its current telemetered consumption, within ten minutes given its ramp rate (and in no case to an amount less than its Minimum Consumption Limit).

(c) **Thirty-Minute Operating Reserve.** For a Dispatchable Asset Related Demand (other than a Storage DARD) that has no Controllable Behind-the-Meter Generation, Thirty-Minute Operating Reserve shall be calculated as the decrease in consumption that the Dispatchable Asset Related Demand could achieve, relative to its current telemetered consumption, within thirty minutes given its ramp rate (and in no case to an amount less than its Minimum Consumption Limit) minus the Ten-Minute Spinning Reserve quantity calculated for the Dispatchable Asset Related Demand pursuant to subsection (a) above. For a Dispatchable Asset Related Demand (other than a Storage DARD) having Controllable Behind-the-Meter Generation, Thirty-Minute Operating Reserve shall be calculated as the decrease in consumption that the Dispatchable Asset Related Demand could achieve, relative to its current telemetered consumption, within thirty minutes given its ramp rate (and in no case to an amount less than its Minimum Consumption Limit)

minus the Ten-Minute Non-Spinning Reserve quantity calculated for the Dispatchable Asset Related Demand pursuant to subsection (b) above.

III.1.7.19.2.3 Demand Response Resources.

For a Demand Response Resource that does not provide one-minute telemetry to the ISO, notwithstanding any provision in this Section III.1.7.19.2.3 to the contrary, the Ten-Minute Spinning Reserve and Ten-Minute Non-Spinning Reserve components of the Real-Time Reserve Designation shall be zero. The Demand Response Resource Ramp Rate used in calculations in this section shall be the lesser of the Resource's offered Demand Response Resource Ramp Rate and its audited Demand Response Resource Ramp Rate as described in Section III.1.5.2.

III.1.7.19.2.3.1 Dispatched.

(a) **Ten-Minute Spinning Reserve.** For a Demand Response Resource that is being dispatched and that has no Controllable Behind-the-Meter Generation, Ten-Minute Spinning Reserve shall be calculated as the increase in demand reduction that the Demand Response Resource could achieve, relative to the estimated current demand reduction level, within ten minutes given its Demand Response Resource Ramp Rate (and in no case greater than its Maximum Reduction). For a Demand Response Resource that is being dispatched and that has Controllable Behind-the-Meter Generation, Ten-Minute Spinning Reserve shall be zero.

(b) **Ten-Minute Non-Spinning Reserve.** For a Demand Response Resource that is being dispatched and that has no Controllable Behind-the-Meter Generation, Ten-Minute Non-Spinning Reserve shall be zero. For a Demand Response Resource that is being dispatched and that has Controllable Behind-the-Meter Generation, Ten-Minute Non-Spinning Reserve shall be calculated as the increase in demand reduction that the Demand Response Resource could achieve, relative to the estimated current demand reduction level, within ten minutes given its Demand Response Resource Ramp Rate (and in no case greater than its Maximum Reduction).

(c) **Thirty-Minute Operating Reserve.** For a Demand Response Resource that is being dispatched, Thirty-Minute Operating Reserve shall be calculated as the increase in demand reduction that the Demand Response Resource could achieve, relative to the estimated current demand reduction level, within thirty minutes given its Demand Response Resource Ramp Rate (and in no case greater than its Maximum Reduction) minus the Ten-Minute Spinning Reserve quantity

calculated for the Resource pursuant to subsection (a) above and the Ten-Minute Non-Spinning Reserve quantity calculated for the Resource pursuant to subsection (b) above.

III.1.7.19.2.3.2 Non-Dispatched.

For a Demand Response Resource that is not being dispatched that is not a Fast Start Demand Response Resource, all components of the Real-Time Reserve Designation shall be zero.

(a) **Ten-Minute Spinning Reserve.** For a Fast Start Demand Response Resource that is not being dispatched, Ten-Minute Spinning Reserve shall be zero.

(b) **Ten-Minute Non-Spinning Reserve.** For a Fast Start Demand Response Resource that is not being dispatched, Ten-Minute Non-Spinning Reserve shall be calculated as the minimum of the Demand Response Resource's Offered CLAIM10, its CLAIM10, and its Maximum Reduction.

(c) **Thirty-Minute Operating Reserve.** For a Fast Start Demand Response Resource that is not being dispatched, Thirty-Minute Operating Reserve shall be calculated as: (i) the minimum of the Demand Response Resource's Offered CLAIM30, its CLAIM30, and its Maximum Reduction, minus (ii) the Ten-Minute Non-Spinning Reserve quantity calculated for the Demand Response Resource pursuant to subsection (b) above.

III.1.7.20 Information and Operating Requirements.

(a) [Reserved.]

(b) Market Participants selling from Resources within the New England Control Area shall: supply to the ISO all applicable Offer Data; report to the ISO Resources that are Self-Scheduled; report to the ISO External Transaction sales; confirm to the ISO bilateral sales to Market Participants within the New England Control Area; respond to the ISO's directives to start, shutdown or change output, consumption, or demand reduction levels of Generator Assets, DARDs, or Demand Response Resources, change scheduled voltages or reactive output levels; continuously maintain all Offer Data concurrent with on-line operating information; and ensure that, where so equipped, equipment is operated with control equipment functioning as specified in the ISO New England Manuals and ISO New England Administrative Procedures.

(c) Market Participants selling from Resources outside the New England Control Area shall: provide to the ISO all applicable Offer Data, including offers specifying amounts of energy available, hours of availability and prices of energy and other services; respond to ISO directives to schedule delivery or change delivery schedules; and communicate delivery schedules to the source Control Area and any intermediary Control Areas.

(d) Market Participants, as applicable, shall: respond or ensure a response to ISO directives for load management steps; report to the ISO all bilateral purchase transactions including External Transaction purchases; and respond or ensure a response to other ISO directives such as those required during Emergency operation.

(e) Market Participant, as applicable, shall provide to the ISO requests to purchase specified amounts of energy for each hour of the Operating Day during which it intends to purchase from the Day-Ahead Energy Market.

(f) Market Participants are responsible for reporting to the ISO anticipated availability and other information concerning Generator Assets, Demand Response Resources and Dispatchable Asset Related Demands required by the ISO New England Operating Documents, including but not limited to the Market Participant's ability to procure fuel and physical limitations that could reduce Resource output or demand reduction capability for the pertinent Operating Day.

III.1.8 ~~[Reserved.]~~Energy Call Option Offers and Day-Ahead Ancillary Services Demand Quantities.

III.1.8.1 Applicability.

The provisions of this Section III.1.8 apply commencing on June 1, 2024.

III.1.8.2 Energy Call Option Offers.

Market Participants may submit Energy Call Option Offers for the Operating Day as specified in this Section III.1.8.2.

(a) Each Energy Call Option Offer shall be associated with a specific Generator Asset or Demand Response Resource for which the Market Participant has submitted a corresponding Supply Offer or Demand Reduction Offer in the Day-Ahead Energy Market for the same hour of the Operating Day.

(b) Each Energy Call Option Offer shall specify: (i) the hour of the Operating Day for which the Energy Call Option Offer applies; (ii) an offer price, in $/MWh, that is greater than or equal to zero; and (iii) an offer quantity, in MWh, that is greater than or equal to zero. The offer price shall not exceed the Reserve Constraint Penalty Factor value specified in Section III.2.6.2(b)(vi) of this Market Rule 1. The offer quantity shall not exceed the Economic Maximum Limit specified in the associated Supply Offer or the Maximum Reduction specified in the associated Demand Reduction Offer.

(c) For each hour of the Operating Day, a Market Participant may submit only one Energy Call Option Offer associated with a specific Generator Asset or Demand Response Resource.

(d) Energy Call Option Offers shall be submitted by the offer submission deadline for the Day-Ahead Energy Market specified in Section III.1.10.1A of this Market Rule 1. An Energy Call Option Offer shall not remain in effect for subsequent Operating Days.

III.1.8.3 Energy Call Option Strike Price.

For each hour of the Operating Day, the ISO shall specify the Energy Call Option Strike Price in $/MWh. The value of the Energy Call Option Strike Price shall represent a forecast of the expected hourly Real-Time Hub Price for each hour of the Operating Day.

The forecast used to determine the Energy Call Option Strike Price shall be based on a publicly-available forecasting algorithm. The ISO shall identify the publicly-available forecasting algorithm and shall review any potential revisions to the forecasting process, prospectively, through the stakeholder process.

The ISO shall post, publicly, the value of the Energy Call Option Strike Price for each hour of the Operating Day no later than two hours before the offer submission deadline for the Day-Ahead Energy Market specified in Section III.1.10.1A of this Market Rule 1, or such other time as necessary to account for software failures or other events.

III.1.8.4 [Reserved.]

III.1.8.5 Day-Ahead Ancillary Services Demand Quantities.

The Day-Ahead Energy Market shall endeavor to procure the demand quantities for the Day-Ahead Ancillary Services specified in this Section III.1.8.5.

(a) For each hour of the Operating Day, the Day-Ahead Ten-Minute Spinning Reserve Demand Quantity shall be equal to the projected Ten-Minute Spinning Reserve Requirement as described in Section III.2.7A of this Market Rule 1 and ISO New England Operating Procedure No. 8.

(b) For each hour of the Operating Day, the Day-Ahead Total Ten-Minute Reserve Demand Quantity shall be equal to the projected Ten-Minute Reserve Requirement as described in Section III.2.7A of this Market Rule 1 and ISO New England Operating Procedure No. 8.

(c) For each hour of the Operating Day, the Day-Ahead Total Thirty-Minute Operating Reserve Demand Quantity shall be equal to the projected Minimum Total Reserve Requirement as described in Section III.2.7A of this Market Rule 1 and ISO New England Operating Procedure No. 8.

(d) For each hour of the Operating Day, the Day-Ahead Total Ninety-Minute Reserve Demand Quantity shall be the sum of (i) the reserve capability sufficient to satisfy the requirements in NERC Reliability Standard BAL-002-3 – Disturbance Control Standard – Contingency Reserve for Recovery from a Balancing Contingency Event, including the restoration of Contingency Reserve within the Contingency Reserve Restoration Period, and (ii) an allowance for load forecast error.

(e) For each hour of the Operating Day, the Day-Ahead Total Four-Hour Reserve Demand Quantity shall be equal to the sum of (i) the reserve capability sufficient to satisfy the requirements of NPCC Regional Reliability Reference Directory No. 5 Reserve, including the restoration of Thirty-Minute Operating Reserve within four hours of a deficiency, and (ii) an allowance for load forecast error.

(f) For each hour of the Operating Day, the Day-Ahead Energy Imbalance Reserve Demand Quantity shall be determined during the scheduling of the Day-Ahead Energy Market. The Day-Ahead Energy Imbalance Reserve Demand Quantity shall be equal to the greater of (a) zero or (b) the value of:
(i) the Forecast Energy Requirement Demand Quantity; less (ii) the sum of the total MWh of all Supply Offers and the total MWh of all Demand Reduction Offers that receive the forecast energy requirement credit, as specified in Section III.3.2.1(q)(5); less (iii) the net total External Transactions (imports minus exports, in MWh) scheduled in the Day-Ahead Energy Market.

III.1.8.6 Forecast Energy Requirement Demand Quantity.

For each hour of the Operating Day, the Forecast Energy Requirement Demand Quantity shall be equal to the ISO forecast for the total loads in the New England Control Area produced pursuant to Section III.1.10.1.A(h) of this Market Rule 1.

III.1.9 Pre-scheduling.

III.1.9.1 Offer and Bid Caps and Cost Verification for Offers and Bids.

III.1.9.1.1 Cost Verification of Resource Offers.

The incremental energy values of Supply Offers and Demand Response Resources above $1,000/MWh for any Resource other than an External Resource are subject to the following cost verification requirements. Unless expressly stated otherwise, cost verification is utilized in all pricing, commitment, dispatch and settlement determinations. For purposes of the following requirements, Reference Levels are calculated using the procedures in Section III.A.7.5 for calculating cost-based Reference Levels.

(a) If the incremental energy value of a Resource's offer is greater than the incremental energy Reference Level value of the Resource, then the incremental energy value in the offer is replaced with the greater of the Reference Level for incremental energy or $1,000/MWh.

(b) For purposes of the price calculations in Sections III.2.5 and III.2.7A, if the adjusted offer calculated under Section III.2.4 for a Rapid Response Pricing Asset is greater than $1,000/MWh (after the incremental energy value is evaluated under Section III.1.9.1.1(a) above), then verification will be performed as follows using a Reference Level value calculated with the adjusted offer formulas specified in Section III.2.4.

(i) If the Reference Level value is less than or equal to $1,000/MWh, then the adjusted offer for the Resource is set at $1,000/MWh;

(ii) If the Reference Level value is greater than $1,000/MWh, then the adjusted offer for the Resource is set at the lower of the Reference Level value and the adjusted offer.

III.1.9.1.2 Offer and Bid Caps.

(a) For purposes of the price calculations described in Section III.2 and for purposes of scheduling a Resource in the Day-Ahead Energy Market in accordance with Section III.1.7.6 following the commitment of the Resource, the incremental energy value of an offer is capped at $2,000/MWh.

(b) Demand Bids shall not specify a bid price below the Energy Offer Floor or above the Demand Bid Cap.

(c) Supply Offers shall not specify an offer price (for incremental energy) below the Energy Offer Floor.

(d) External Transactions shall not specify a price below the External Transaction Floor or above the External Transaction Cap.

(e) Increment Offers and Decrement Bids shall not specify an offer or bid price below the Energy Offer Floor or above the Virtual Cap.

III.1.9.2 [Reserved.]

III.1.9.3 [Reserved.]

III.1.9.4 [Reserved.]

III.1.9.5 [Reserved.]

III.1.9.6 [Reserved.]

III.1.9.7 Market Participant Responsibilities.

Market Participants authorized and intending to request market-based Start-Up Fees and No-Load Fee in their Offer Data shall submit a specification of such fees to the ISO for each Generator Asset as to which the Market Participant intends to request such fees. Any such specification shall identify the applicable period and be submitted on or before the applicable deadline and shall remain in effect unless otherwise modified in accordance with Section III.1.10.9. The ISO shall reject any request for Start-Up Fees and No-Load Fee in a Market Participant's Offer Data that does not conform to the Market Participant's specification on file with the ISO.

III.1.9.8 [Reserved.]

III.1.10 Scheduling.

III.1.10.1 General.

(a) The ISO shall administer scheduling processes to implement a Day-Ahead Energy Market and a Real-Time Energy Market.

(b) The Day-Ahead Energy Market shall enable Market Participants to purchase and sell energy and, commencing on June 1, 2024, sell ancillary services through the New England Markets at the applicable Day-Ahead Prices, and enable Market Participants to submit External Transactions conditioned upon

Congestion Costs not exceeding a specified level. Market Participants whose purchases and sales and External Transactions are scheduled in the Day-Ahead Energy Market shall be obligated to purchase or sell energy or pay Congestion Costs and costs for losses, at the applicable Day-Ahead Prices for the amounts scheduled.

(c) In the Real-Time Energy Market,

(i) Market Participants that deviate from the amount of energy purchases or sales scheduled in the Day-Ahead Energy Market shall replace the energy not delivered with energy from the Real-Time Energy Market or an internal bilateral transaction and shall pay for such energy not delivered, net of any internal bilateral transactions, at the applicable Real-Time Price, unless otherwise specified by this Market Rule 1, and

(ii) Non-Market Participant Transmission Customers shall be obligated to pay Congestion Costs and costs for losses for the amount of the scheduled transmission uses in the Real-Time Energy Market at the applicable Real-Time Congestion Component and Loss Component price differences, unless otherwise specified by this Market Rule 1.

(d) The following scheduling procedures and principles shall govern the commitment of Resources to the Day-Ahead Energy Market and the Real-Time Energy Market over a period extending from one week to one hour prior to the Real-Time dispatch. Scheduling encompasses the Day-Ahead and hourly scheduling process, through which the ISO determines the Day-Ahead Energy Market schedule and determines, based on changing forecasts of conditions and actions by Market Participants and system constraints, a plan to serve the hourly energy and reserve requirements of the New England Control Area in the least costly manner, subject to maintaining the reliability of the New England Control Area. Scheduling of External Transactions in the Real-Time Energy Market is subject to Section II.44 of the OATT.

(e) If the ISO's forecast for the next seven days projects a likelihood of Emergency Condition, the ISO may commit, for all or part of such seven day period, to the use of Generator Assets or Demand Response Resources with Notification Time greater than 24 hours as necessary in order to alleviate or mitigate such Emergency, in accordance with the Market Participants' binding Supply Offers or Demand Reduction Offers.

III.1.10.1A **Energy Market Scheduling**.

The submission of Day-Ahead offers and bids shall occur not later than 10:00 a.m. on the day before the Operating Day for which transactions are being scheduled, or such other deadline as may be specified by the ISO in order to comply with the practical requirements and the economic and efficiency objectives of the scheduling process specified in this Market Rule 1.

(a) **Locational Demand Bids –** Each Market Participant may submit to the ISO specifications of the amount and location of its customer loads and/or energy purchases to be included in the Day-Ahead Energy Market for each hour of the next Operating Day, such specifications to comply with the requirements set forth in the ISO New England Manuals and ISO New England Administrative Procedures. Each Market Participant shall inform the ISO of (i) the prices, if any, at which it desires not to include its load in the Day-Ahead Energy Market rather than pay the applicable Day-Ahead Price, (ii) hourly schedules for Resources Self-Scheduled by the Market Participant; and (iii) the Decrement Bid at which each such Self-Scheduled Resource will disconnect or reduce output, or confirmation of the Market Participant's intent not to reduce output. Price-sensitive Demand Bids and Decrement Bids must be greater than zero MW and shall not exceed the Demand Bid Cap and Virtual Cap.

(b) **External Transactions –** All Market Participants shall submit to the ISO schedules for any External Transactions involving use of Generator Assets or the New England Transmission System as specified below, and shall inform the ISO whether the transaction is to be included in the Day-Ahead Energy Market. Any Market Participant that elects to include an External Transaction in the Day-Ahead Energy Market may specify the price (such price not to exceed the maximum price that may be specified in the ISO New England Manuals and ISO New England Administrative Procedures), if any, at which it will be curtailed rather than pay Congestion Costs. The foregoing price specification shall apply to the price difference between the Locational Marginal Prices for specified External Transaction source and sink points in the Day-Ahead scheduling process only. Any Market Participant that deviates from its Day-Ahead External Transaction schedule or elects not to include its External Transaction in the Day-Ahead Energy Market shall be subject to Congestion Costs in the Real-Time Energy Market in order to complete any such scheduled External Transaction. Scheduling of External Transactions shall be conducted in accordance with the specifications in the ISO New England Manuals and ISO New England Administrative Procedures and the following requirements:

(i) Market Participants shall submit schedules for all External Transaction purchases for delivery within the New England Control Area from Resources outside the New England Control Area;

(ii) Market Participants shall submit schedules for External Transaction sales to entities outside the New England Control Area from Resources within the New England Control Area;

(iii) In the Day-Ahead Energy Market, if the sum of all submitted Self-Scheduled External Transaction purchases less External Transaction sales exceeds the import capability associated with the applicable External Node, the offer prices for all Self-Scheduled External Transaction purchases at the applicable External Node shall be set equal to the Energy Offer Floor;

(iv) In the Day-Ahead Energy Market, if the sum of all submitted Self-Scheduled External Transaction sales less External Transaction purchases exceeds the export capability associated with the applicable External Node, the offer prices for all Self-Scheduled External Transaction sales at the applicable External Node shall be set equal to the External Transaction Cap;

(v) The ISO shall not consider Start-Up Fees, No-Load Fees, Notification Times or any other inter-temporal parameters in scheduling or dispatching External Transactions.

(c) **Generator Asset Supply Offers –** Market Participants selling into the New England Markets from Generator Assets may submit Supply Offers for the supply of energy for the following Operating Day.

Such Supply Offers:

(i) Shall specify the Resource and Blocks (price and quantity of Energy) for each hour of the Operating Day for each Resource offered by the Market Participant to the ISO. The prices and quantities in a Block may each vary on an hourly basis;

(ii) If based on energy from a Generator Asset internal to the New England Control Area, may specify, for Supply Offers, a Start-Up Fee and No-Load Fee for each hour of the Operating Day. Start-Up Fee and No-Load Fee may vary on an hourly basis;

(iii) Shall specify, for Supply Offers from a dual-fuel Generator Asset, the fuel type. The fuel type may vary on an hourly basis. A Market Participant that submits a Supply Offer using the higher cost fuel type must satisfy the consultation requirements for dual-fuel Generator Assets in Section III.A.3 of Appendix A;

(iv) Shall specify a Minimum Run Time to be used for commitment purposes that does not exceed 24 hours;

(v) Supply Offers shall constitute an offer to submit the Generator Asset to the ISO for commitment and dispatch in accordance with the terms of the Supply Offer, where such Supply Offer, with regard to operating limits, shall specify changes, including to the Economic Maximum Limit, Economic Minimum Limit and Emergency Minimum Limit, from those submitted as part of the Resource's Offer Data to reflect the physical operating characteristics and/or availability of the Resource (except that for a Limited Energy Resource, the Economic Maximum Limit may be revised to reflect an energy (MWh) limitation), which offer shall remain open through the Operating Day for which the Supply Offer is submitted; and

(vi) Shall, in the case of a Supply Offer from a Generator Asset associated with an Electric Storage Facility, also meet the requirements specified in Section III.1.10.6.

(d) DARD Demand Bids – Market Participants participating in the New England Markets with Dispatchable Asset Related Demands may submit Demand Bids for the consumption of energy for the following Operating Day.

Such Demand Bids:

(i) Shall specify the Dispatchable Asset Related Demand and Blocks (price and Energy quantity pairs) for each hour of the Operating Day for each Dispatchable Asset Related Demand offered by the Market Participant to the ISO. The prices and quantities in a Block may each vary on an hourly basis;

(ii) Shall constitute an offer to submit the Dispatchable Asset Related Demand to the ISO for commitment and dispatch in accordance with the terms of the Demand Bid, where such Demand Bid, with regard to operating limits, shall specify changes, including to the Maximum Consumption Limit and Minimum Consumption Limit, from those submitted as part of the

Resource's Offer Data to reflect the physical operating characteristics and/or availability of the Resource;

(iii) Shall specify a Minimum Consumption Limit that is less than or equal to its Nominated Consumption Limit; and

(iv) Shall, in the case of a Demand Bid from a Storage DARD, also meet the requirements specified in Section III.1.10.6.

(e) **Demand Response Resource Demand Reduction Offers –** Market Participants selling into the New England Markets from Demand Response Resources may submit Demand Reduction Offers for the supply of energy for the following Operating Day. A Demand Reduction Offer shall constitute an offer to submit the Demand Response Resource to the ISO for commitment and dispatch in accordance with the terms of the Demand Reduction Offer. Demand Reduction Offers:

(i) Shall specify the Demand Response Resource and Blocks (price and demand reduction quantity pairs) for each hour of the Operating Day. The prices and demand reduction quantities may vary on an hourly basis.

(ii) Shall not specify a price that is above the Energy Offer Cap, below the Energy Offer Floor, or below the Demand Reduction Threshold Price in effect for the Operating Day. For purposes of clearing the Day-Ahead and Real-Time Energy Markets and calculating Day-Ahead and Real-Time Locational Marginal Prices and Real-Time Reserve Clearing Prices, any price specified below the Demand Reduction Threshold price in effect for the Operating Day will be considered to be equal to the Demand Reduction Threshold Price for the Operating Day.

(iii) Shall not include average avoided peak transmission or distribution losses in the demand reduction quantity.

(iv) May specify an Interruption Cost for each hour of the Operating Day, which may vary on an hourly basis.

(v) Shall specify a Minimum Reduction Time to be used for scheduling purposes that does not exceed 24 hours.

(vi) Shall specify a Maximum Reduction amount no greater than the sum of the Maximum Interruptible Capacities of the Demand Response Resource's operational Demand Response Assets.

(vii) Shall specify changes to the Maximum Reduction and Minimum Reduction from those submitted as part of the Demand Response Resource's Offer Data to reflect the physical operating characteristics and/or availability of the Demand Response Resource.

(f) **Demand Reduction Threshold Price –** The Demand Reduction Threshold Price for each month shall be determined through an analysis of a smoothed, historic supply curve for the month. The historic supply curve shall be derived from Real-Time generator and import Offer Data <u>(excluding Coordinated External Transactions)</u> for the same month of the previous year. The ISO may adjust the Offer Data to account for significant changes in generator and import availability or other significant changes to the historic supply curve. The historic supply curve shall be calculated as follows:

(a) Each generator and import offer Block (i.e., each price-quantity pair offered in the Real-Time Energy Market) for each day of the month shall be compiled and sorted in ascending order of price to create an unsmoothed supply curve.

(b) An unsmoothed supply curve for the month shall be formed from the price and cumulative quantity of each offer Block.

(c) A non-linear regression shall be performed on a sampled portion of the unsmoothed supply curve to produce an increasing, convex, smooth approximation of the supply curve.

(d) A historic threshold price P_{th} shall be determined as the point on the smoothed supply curve beyond which the benefit to load from the reduced LMP resulting from the demand reduction of Demand Response Resources exceeds the cost to load associated with compensating Demand Response Resources for demand reduction.

(e) The Demand Reduction Threshold Price for the upcoming month shall be determined by the following formula:

$$DRTP = P_{th} X — \frac{FPI_c}{FPI_h}$$

where FPI_h is the historic fuel price index for the same month of the previous year, and FPI_c is the fuel price index for the current month.

The historic and current fuel price indices used to establish the Demand Reduction Threshold Price for a month shall be based on the lesser of the monthly natural gas or heating oil fuel indices applicable to the New England Control Area, as calculated three business days before the start of the month preceding the Demand Reduction Threshold Price's effective date.

The ISO will post the Demand Reduction Threshold Price, along with the index-based fuel price values used in establishing the Demand Reduction Threshold Price, on its website by the 15th day of the month preceding the Demand Reduction Threshold Price's effective date.

(g) **Subsequent Operating Days** – Each Supply Offer, Demand Reduction Offer, or Demand Bid by a Market Participant of a Resource shall remain in effect for subsequent Operating Days until superseded or canceled except in the case of an External Transaction purchase, in which case, the Supply Offer shall remain in effect for the applicable Operating Day and shall not remain in effect for subsequent Operating Days. Hourly overrides of a Supply Offer, a Demand Reduction Offer, or a Demand Bid shall remain in effect only for the applicable Operating Day.

(h) **Load Estimate** – The ISO shall post on the internet the total hourly loads including Decrement Bids scheduled in the Day-Ahead Energy Market, as well as the ISO's estimate of the Control Area hourly load for the next Operating Day.

(i) **Prorated Supply** – In determining Day-Ahead schedules, in the event of multiple marginal Supply Offers, Demand Reduction Offers, Increment Offers and/or External Transaction purchases at a pricing location, the ISO shall clear the marginal Supply Offers, Demand Reduction Offers, Increment Offers and/or External Transaction purchases proportional to the amount of energy (MW) from each marginal offer and/or External Transaction at the pricing location. The Economic Maximum Limits, Economic Minimum Limits, Minimum Reductions and Maximum Reductions are not used in determining the amount of energy (MW) in each marginal Supply Offer or Demand Reduction Offer to be cleared on a pro-rated basis. However, the Day-Ahead schedules resulting from the pro-ration process will reflect Economic Maximum Limits, Economic Minimum Limits, Minimum Reductions and Maximum Reductions.

(j) **Prorated Demand** – In determining Day-Ahead schedules, in the event of multiple marginal Demand Bids, Decrement Bids and/or External Transaction sales at a pricing location, the ISO shall clear the marginal Demand Bids, Decrement Bids and/or External Transaction sales proportional to the amount of energy (MW) from each marginal bid and/or External Transaction at the pricing location.

(k) **Virtuals** – All Market Participants may submit Increment Offers and/or Decrement Bids that apply to the Day-Ahead Energy Market only. Such offers and bids must comply with the requirements set forth in the ISO New England Manuals and ISO New England Administrative Procedures and must specify amount, location and price, if any, at which the Market Participant desires to purchase or sell energy in the Day-Ahead Energy Market.

(l) **Energy Call Option Offers** – Market Participants selling into the New England Markets from Generator Assets or Demand Response Resources may submit Energy Call Option Offers for the following Operating Day. Energy Call Option Offers shall be submitted to the ISO in accordance with Section III.1.8.2 of this Market Rule 1.

III.1.10.2 Pool-Scheduled Resources.

Pool-Scheduled Resources are those Resources for which Market Participants submitted Supply Offers, Demand Reduction Offers, or Demand Bids in the Day-Ahead Energy Market and which the ISO scheduled in the Day-Ahead Energy Market as well as Generator Assets, DARDs or Demand Response Resources committed by the ISO subsequent to the Day-Ahead Energy Market. Such Resources shall be committed to provide or consume energy in the Real-Time dispatch unless the schedules for such Resources are revised pursuant to Sections III.1.10.9 or III.1.11. Pool-Scheduled Resources shall be governed by the following principles and procedures.

(a) Pool-Scheduled Resources shall be selected by the ISO on the basis of the prices offered for energy supply or consumption and related services, Start-Up Fees, No-Load Fees, Interruption Cost and the specified operating characteristics, offered by Market Participants.

(b) The ISO shall optimize the dispatch of energy, and commencing on June 1, 2024, energy and ancillary services, from Limited Energy Resources by request to minimize the as-bid production cost for the New England Control Area. In implementing the use of Limited Energy Resources, the ISO shall use its best efforts to select the most economic hours of operation for Limited Energy Resources, in order to make optimal use of such Resources in the Day-Ahead Energy Market consistent with the Supply Offers and Demand Reduction Offers of other Resources, the submitted Demand Bids and Decrement Bids, and ~~Operating Reserve and Replacement Reserve~~ ancillary services requirements procured pursuant to this Market Rule 1.

(c) Market Participants offering energy from facilities with fuel or environmental limitations may submit data to the ISO that is sufficient to enable the ISO to determine the available operating hours of such facilities.

(d) Market Participants shall make available their Pool-Scheduled Resources to the ISO for coordinated operation to supply the needs of the New England Control Area for energy and ancillary services.

III.1.10.3 Self-Scheduled Resources.

A Resource that is Self-Scheduled shall be governed by the following principles and procedures. The minimum duration of a Self-Schedule for a Generator Asset or DARD shall not result in the Generator Asset or DARD operating for less than its Minimum Run Time. A Generator Asset that is online as a result of a Self-Schedule will be dispatched above its Economic Minimum Limit based on the economic merit of its Supply Offer. A DARD that is consuming as a result of a Self-Schedule may be dispatched above its Minimum Consumption Limit based on the economic merit of its Demand Bid. A Demand Response Resource shall not be Self-Scheduled.

III.1.10.4 External Resources.

Market Participants with External Resources may submit External Transactions as detailed in Section III.1.10.7 and Section III.1.10.7.A of this Market Rule 1.

III.1.10.5 Dispatchable Asset Related Demand.

(a) External Transactions that are sales to an external Control Area are not eligible to be Dispatchable Asset Related Demands.

(b) A Market Participant with a Dispatchable Asset Related Demand in the New England Control Area must:

(i) notify the ISO of any outage (including partial outages) that may reduce the Dispatchable Asset Related Demand's ability to respond to Dispatch Instructions and the expected return date from the outage;

(ii) in accordance with the ISO New England Manuals and Operating Procedures, perform audit tests and submit the results to the ISO or provide to the ISO appropriate historical production data;

(iii) abide by the ISO maintenance coordination procedures; and

(iv) provide information reasonably requested by the ISO, including the name and location of the Dispatchable Asset Related Demand.

III.1.10.6 Electric Storage

A storage facility is a facility that is capable of receiving electricity from the grid and storing the energy for later injection of electricity back to the grid. A storage facility may participate in the New England Markets as described below.

(a) A storage facility that satisfies the requirements of this subsection (a) may participate in the New England Markets as an Electric Storage Facility. An Electric Storage Facility shall:

(i) comprise one or more storage facilities at the same point of interconnection;

(ii) have the ability to inject at least 0.1 MW and consume at least 0.1 MW;

(iii) be directly metered;

(iv) be registered as, and subject to all rules applicable to, a dispatchable Generator Asset;

(v) be registered as, and subject to all rules applicable to, a DARD that represents the same equipment as the Generator Asset;

(vi) settle its injection of electricity to the grid as a Generator Asset and its receipt of electricity from the grid as a DARD;

(vii) not be precluded from providing retail services so long as it is able to fulfill its wholesale Energy Market and Forward Capacity Market obligations including, but not limited to, satisfying meter data reporting requirements and notifying the ISO of any changes to operational capabilities; and

(viii) meet the requirements of either a Binary Storage Facility or a Continuous Storage Facility, as described in subsections (b) and (c) below.

(b) A storage facility that satisfies the requirements of this subsection (b) may participate in the New England Markets as a Binary Storage Facility. A Binary Storage Facility shall:

(i) satisfy the requirements applicable to an Electric Storage Facility; and

(ii) offer its Generator Asset and DARD into the Energy Market as Rapid Response Pricing Assets; and

(iii) be issued Dispatch Instructions in a manner that ensures the facility is not required to consume and inject simultaneously.

(c) A storage facility that satisfies the requirements of this subsection (c) may participate in the New England Markets as a Continuous Storage Facility. A Continuous Storage Facility shall:

(i) satisfy the requirements applicable to an Electric Storage Facility;

(ii) be registered as, may provide Regulation as, and is subject to all rules applicable to, an ATRR that represents the same equipment as the Generator Asset and DARD;

(iii) be capable of transitioning between the facility's maximum output and maximum consumption (and vice versa) in ten minutes or less;

(iv) not utilize storage capability that is shared with another Generator Asset, DARD or ATRR;

(v) specify in Supply Offers a zero MW value for Economic Minimum Limit and Emergency Minimum Limit (except for Generator Assets undergoing Facility and Equipment Testing or auditing); a zero time value for Minimum Run Time, Minimum Down Time, Notification Time, and Start-Up Time; and a zero cost value for Start-Up Fee and No-Load Fee;

(vi) specify in Demand Bids a zero MW value for Minimum Consumption Limit (except for DARDs undergoing Facility and Equipment Testing or auditing) and a zero time value for Minimum Run Time and Minimum Down Time;

(vii) be Self-Scheduled in the Day-Ahead Energy Market and Real-Time Energy Market, and operate in an on-line state, unless the facility is declared unavailable by the Market Participant; and

(viii) be issued a combined dispatch control signal equal to the Desired Dispatch Point (of the Generator Asset) minus the Desired Dispatch Point (of the DARD) plus the AGC SetPoint (of the ATRR).

(d) A storage facility shall comply with all applicable registration, metering, and accounting rules including, but not limited to, the following:

(i) A Market Participant wishing to purchase energy from the ISO-administered wholesale markets must first, jointly with its Host Participant, register one or more wholesale Load Assets with the ISO as described in ISO New England Manual M-28 and ISO New

England Manual M-RPA; where the Market Participant wishes to register an Electric Storage Facility, the registered Load Asset must be a DARD.

(ii) A storage facility's charging load shall not qualify as a DARD if the Host Participant is unwilling or unable to support the registration, metering, and accounting of the storage facility's load as a separate and distinct Load Asset. A storage facility registered as a DARD will be charged the nodal Locational Marginal Price by the ISO and the Market Participant will not pay twice for the same charging load.

(iii) The registration and metering of all Assets must comply with ISO New England Operating Procedure No. 14 and ISO New England Operating Procedure No. 18, including with the requirement that an Asset's revenue metering must comply with the accuracy requirements found in ISO New England Operating Procedure No. 18.

(iv) Pursuant to ISO New England Manual M-28, the Assigned Meter Reader, the Host Participant, and the ISO provide the data for use in the daily settlement process within the timelines described in the manual. The data may be five-minute interval data, and may be no more than hourly data, as described in Section III.3.2 and in ISO New England Manual M-28.

(v) Based on the Metered Quantity For Settlement and the Locational Marginal Price in the settlement interval, the ISO shall conduct all Energy Market accounting pursuant to Section III.3.2.1.

(e) A facility registered as a dispatchable Generator Asset, an ATRR, and a DARD that each represent the same equipment must participate as a Continuous Storage Facility.

(f) A storage facility not participating as an Electric Storage Facility may, if it satisfies the associated requirements, be registered as a Generator Asset (including a Settlement Only Resource) for settlement of its injection of electricity to the grid and as an Asset Related Demand for settlement of its wholesale load.

(g) A storage facility may, if it satisfies the associated requirements, be registered as a Demand Response Asset. (As described in Section III.8.1.1, a Demand Response Asset and a Generator Asset may not be registered at the same end-use customer facility unless the Generator Asset is separately metered and reported and its output does not reduce the load reported at the Retail Delivery Point of the Demand Response Asset.)

(h) A storage device may, if it satisfies the associated requirements, be registered as a component of either an On-Peak Demand Resource or a Seasonal Peak Demand Resource.

(i) A storage facility may, if it satisfies the associated requirements, provide Regulation pursuant to Section III.14.

III.1.10.7 External Transactions.

The provisions of this Section III.1.10.7 do not apply to Coordinated External Transactions.

(a) Market Participants that submit an External Transaction in the Day-Ahead Energy Market must also submit a corresponding External Transaction in the Real-Time Energy Market in order to be eligible for scheduling in the Real-Time Energy Market. Priced External Transactions for the Real-Time Energy Market must be submitted by the offer submission deadline for the Day-Ahead Energy Market.

(b) Priced External Transactions submitted in both the Day-Ahead Energy Market and the Real-Time Energy Market will be treated as Self-Scheduled External Transactions in the Real-Time Energy Market for the associated megawatt amounts that cleared the Day-Ahead Energy Market, unless the Market Participant modifies the price component of its Real-Time offer during the Re-Offer Period.

(c) Any External Transaction, or portion thereof, submitted to the Real-Time Energy Market that did not clear in the Day-Ahead Energy Market will not be scheduled in Real-Time if the ISO anticipates that the External Transaction would create or worsen an Emergency. External Transactions cleared in the Day-Ahead Energy Market and associated with a Real-Time Energy Market submission will continue to be scheduled in Real-Time prior to and during an Emergency, until the procedures governing the Emergency, as set forth in ISO New England Operating Procedure No. 9, require a change in schedule.

(d) External Transactions submitted to the Real-Time Energy Market must contain the associated e-Tag ID and transmission reservation, if required, at the time the transaction is submitted to the Real-Time Energy Market.

(e) [Reserved.]

(f) External Transaction sales meeting all of the criteria for any of the transaction types described in (i) through (iv) below receive priority in the scheduling and curtailment of transactions as set forth in

Section II.44 of the OATT. External Transaction sales meeting all of the criteria for any of the transaction types described in (i) through (iv) below are referred to herein and in the OATT as being supported in Real-Time.

(i) Capacity Export Through Import Constrained Zone Transactions:

(1) The External Transaction is exporting across an external interface located in an import-constrained Capacity Zone that cleared in the Forward Capacity Auction with price separation, as determined in accordance with Section III.12.4 and Section III.13.2.3.4 of Market Rule 1;

(2) The External Transaction is directly associated with an Export Bid or Administrative Export De-List Bid that cleared in the Forward Capacity Auction, and the megawatt amount of the External Transaction is less than or equal to the megawatt amount of the cleared Export Bid;

(3) The External Node associated with the cleared Export Bid or Administrative Export De-List Bid is connected to the import-constrained Capacity Zone, and is not connected to a Capacity Zone that is not import-constrained;

(4) The Resource, or portion thereof, that is associated with the cleared Export Bid or Administrative Export De-List Bid is not located in the import-constrained Capacity Zone;

(5) The External Transaction has been submitted and cleared in the Day-Ahead Energy Market;

(6) A matching External Transaction has also been submitted into the Real-Time Energy Market by the end of the Re-Offer Period for Self-Scheduled External Transactions, and, in accordance with Section III.1.10.7(a), by the offer submission deadline for the Day-Ahead Energy Market for priced External Transactions.

(ii) FCA Cleared Export Transactions:

(1) The External Transaction sale is exporting to an External Node that is connected only to an import-constrained Reserve Zone;

(2) The External Transaction sale is directly associated with an Export Bid or an Administrative Export De-List Bid that cleared in the Forward Capacity Auction, and the megawatt amount of the External Transaction is less than or equal to the megawatt amount of the cleared Export Bid;

(3) The Resource, or portion thereof, without a Capacity Supply Obligation associated with the Export Bid or Administrative Export De-List Bid is located outside the import-constrained Reserve Zone;

(4) The External Transaction sale is submitted and cleared in the Day-Ahead Energy Market;

(5) A matching External Transaction has also been submitted into the Real-Time Energy Market by the end of the Re-Offer Period for Self-Scheduled External Transactions, and, in accordance with Section III.1.10.7(a), by the offer submission deadline for the Day-Ahead Energy Market for priced External Transactions.

(iii) Same Reserve Zone Export Transactions:

(1) A Resource, or portion thereof, without a Capacity Supply Obligation is associated with the External Transaction sale, and the megawatt amount of the External Transaction is less than or equal to the portion of the Resource without a Capacity Supply Obligation;

(2) The External Node of the External Transaction sale is connected only to the same Reserve Zone in which the associated Resource, or portion thereof, without a Capacity Supply Obligation is located;

(3) The Resource, or portion thereof, without a Capacity Supply Obligation is Self-Scheduled in the Real-Time Energy Market and online at a megawatt level greater than or equal to the External Transaction sale’s megawatt amount;

(4) Neither the External Transaction sale nor the portion of the Resource without a Capacity Supply Obligation is required to offer into the Day-Ahead Energy Market.

(iv) Unconstrained Export Transactions:

(1) A Resource, or portion thereof, without a Capacity Supply Obligation is associated with the External Transaction sale, and the megawatt amount of the External Transaction is less than or equal to the portion of the Resource without a Capacity Supply Obligation;

(2) The External Node of the External Transaction sale is not connected only to an import-constrained Reserve Zone;

(3) The Resource, or portion thereof, without a Capacity Supply Obligation is not separated from the External Node by a transmission interface constraint as determined in Sections III.12.2.1(b) and III.12.2.2(b) of Market Rule 1 that was binding in the Forward Capacity Auction in the direction of the export;

(4) The Resource, or portion thereof, without a Capacity Supply Obligation is Self-Scheduled in the Real-Time Energy Market and online at a megawatt level greater than or equal to the External Transaction sale's megawatt amount;

(5) Neither the External Transaction sale, nor the portion of the Resource without a Capacity Supply Obligation is required to offer into the Day-Ahead Energy Market.

(g) Treatment of External Transaction sales in ISO commitment for local second contingency protection.

(i) Capacity Export Through Import Constrained Zone Transactions and FCA Cleared Export Transactions: The transaction's export demand that clears in the Day-Ahead Energy Market will be explicitly considered as load in the exporting Reserve Zone by the ISO when committing Resources to provide local second contingency protection for the associated Operating Day.

(ii) The export demand of External Transaction sales not meeting the criteria in (i) above is not considered by the ISO when planning and committing Resources to provide local second contingency protection, and is assumed to be zero.

(iii) Same Reserve Zone Export Transactions and Unconstrained Export Transactions: If a Resource, or portion thereof, without a Capacity Supply Obligation is committed to be online during the Operating Day either through clearing in the Day-Ahead Energy Market or through Self-Scheduling subsequent to the Day-Ahead Energy Market and a Same Reserve Zone Export Transaction or Unconstrained Export Transaction is submitted before the end of the Re-Offer Period designating that Resource as supporting the transaction, the ISO will not utilize the portion of the Resource without a Capacity Supply Obligation supporting the export transaction to meet local second contingency protection requirements. The eligibility of Resources not meeting the foregoing criteria to be used to meet local second contingency protection requirements shall be in accordance with the relevant provisions of the ISO New England System Rules.

(h) Allocation of costs to Capacity Export Through Import Constrained Zone Transactions and FCA Cleared Export Transactions: Market Participants with Capacity Export Through Import Constrained Zone Transactions and FCA Cleared Export Transactions shall incur a proportional share of the charges described below, which are allocated to Market Participants based on Day-Ahead Load Obligation or Real-Time Load Obligation. The share shall be determined by including the Day-Ahead Load Obligation or Real-Time Load Obligation associated with the External Transaction, as applicable, in the total Day-Ahead Load Obligation or Real-Time Load Obligation for the appropriate Reliability Region, Reserve Zone, or Load Zone used in each cost allocation calculation:

(i) NCPC for Local Second Contingency Protection Resources allocated within the exporting Reliability Region, pursuant to Section III.F.3.3.

(ii) Forward Reserve Market charges allocated within the exporting Load Zone, pursuant to Section III.9.9.

(iii) Real-Time Reserve Charges allocated within the exporting Load Zone, pursuant to Section III.10.3.

(i) When action is taken by the ISO to reduce External Transaction sales due to a system wide capacity deficient condition or the forecast of such a condition, and an External Transaction sale designates a Resource, or portion of a Resource, without a Capacity Supply Obligation, to support the transaction, the ISO will review the status of the designated Resource. If the designated Resource is Self-Scheduled and online at a megawatt level greater than or equal to the External Transaction sale, that

External Transaction sale will not be reduced until such time as Regional Network Load within the New England Control Area is also being reduced. When reductions to such transactions are required, the affected transactions shall be reduced pro-rata.

(j) Market Participants shall submit External Transactions as megawatt blocks with intervals of one hour at the relevant External Node. External Transactions will be scheduled in the Day-Ahead Energy Market as megawatt blocks for hourly durations. The ISO may dispatch External Transactions in the Real-Time Energy Market as megawatt blocks for periods of less than one hour, to the extent allowed pursuant to inter-Control Area operating protocols.

III.1.10.7.A Coordinated Transaction Scheduling.

The provisions of this Section III.1.10.7.A apply to Coordinated External Transactions, which are implemented at the New York Northern AC external Location.

(a) Market Participants that submit a Coordinated External Transaction in the Day-Ahead Energy Market must also submit a corresponding Coordinated External Transaction, in the form of an Interface Bid, in the Real-Time Energy Market in order to be eligible for scheduling in the Real-Time Energy Market.

(b) An Interface Bid submitted in the Real-Time Energy Market shall specify a duration consisting of one or more consecutive 15-minute increments. An Interface Bid shall include a bid price, a bid quantity, and a bid direction for each 15-minute increment. The bid price may be positive or negative. An Interface Bid may not be submitted or modified later than 75 minutes before the start of the clock hour for which it is offered.

(c) Interface Bids are cleared in economic merit order for each 15-minute increment, based upon the forecasted real-time price difference across the external interface. The total quantity of Interface Bids cleared shall determine the external interface schedule between New England and the adjacent Control Area. The total quantity of Interface Bids cleared shall depend upon, among other factors, bid production costs of resources in both Control Areas, the Interface Bids of all Market Participants, transmission system conditions, and any real-time operating limits necessary to ensure reliable operation of the transmission system.

(d) All Coordinated External Transactions submitted either to the Day-Ahead Energy Market or the Real-Time Energy Market must contain the associated e-Tag ID at the time the transaction is submitted.

(e) Any Coordinated External Transaction, or portion thereof, submitted to the Real-Time Energy Market will not be scheduled in Real-Time if the ISO anticipates that the External Transaction would create or worsen an Emergency, unless the procedures governing the Emergency, as set forth in ISO New England Operating Procedure No. 9, permit the transaction to be scheduled.

III.1.10.8 ISO Responsibilities.

(a) Scheduling Considerations

(i) Prior to June 1, 2024, t~~T~~he ISO shall use its best efforts to determine (~~i~~1) the least-cost means of satisfying hourly purchase requests for energy, the projected hourly requirements for Operating Reserve, Replacement Reserve and other ancillary services of the Market Participants, including the reliability requirements of the New England Control Area, of the Day-Ahead Energy Market, and (~~ii~~2) the least-cost means of satisfying the Operating Reserve, Replacement Reserve and other ancillary service requirements for any portion of the load forecast of the ISO for the Operating Day in excess of that scheduled in the Day-Ahead Energy Market.

In making the~~se~~ determinations specified in this subsection (a)(i), the ISO shall take into account: (i) the ISO's forecasts of New England Markets and New England Control Area energy requirements, giving due consideration to the energy requirement forecasts and purchase requests submitted by Market Participants for the Day-Ahead Energy Market; (ii) the offers and bids submitted by Market Participants; (iii) the availability of Limited Energy Resources; (iv) the capacity, location, and other relevant characteristics of Self-Scheduled Resources; (v) the requirements of the New England Control Area for Operating Reserve and Replacement Reserve, as specified in the ISO New England Manuals and ISO New England Administrative Procedures; (vi) the requirements of the New England Control Area for Regulation and other ancillary services, as specified in the ISO New England Manuals and ISO New England Administrative Procedures; (vii) the benefits of avoiding or minimizing transmission constraint control operations, as specified in the ISO New England Manuals and ISO New England Administrative Procedures; and (viii) such other factors as the ISO reasonably concludes are relevant to the foregoing determination. The ISO shall develop a Day-Ahead Energy schedule based on the applicable portions of the foregoing determination, and shall determine the Day-Ahead Prices resulting from such schedule.

(ii) Commencing on June 1, 2024, in scheduling the Day-Ahead Energy Market, the ISO shall use its best efforts to determine the security-constrained economic commitment and dispatch that jointly optimizes: (1) Demand Bids, Decrement Bids, Demand Reduction Offers, Supply Offers, Increment Offers, and External Transactions, for energy; (2) Energy Call Option Offers to satisfy the Day-Ahead Ancillary Services demand quantities; and (3) Supply Offers, Demand Reduction Offers, External Transactions, and Energy Call Option Offers to satisfy the Forecast Energy Requirement Demand Quantity.

In making the determinations specified in this subsection (a)(ii), the ISO shall take into account, as applicable: (1) the ISO's forecasts of New England Markets and New England Control Area energy requirements, giving due consideration to the energy requirement forecasts and purchase requests submitted by Market Participants for the Day-Ahead Energy Market; (2) the offers and bids submitted by Market Participants; (3) the availability of Limited Energy Resources; (4) capacity, location, and other relevant characteristics of Self-Scheduled Resources; (5) the requirements of the New England Control Area for ancillary services; (6) the operational capabilities of any Resource to adjust the output, consumption, or demand reduction within the operating characteristics specified in the Market Participant's Offer Data, Supply Offer, Demand Reduction Offer, or Demand Bid; (7) the benefits of avoiding or minimizing transmission constraint control operations, as specified in the ISO New England Manuals and ISO New England Administrative Procedures; and (8) such other factors as the ISO reasonably concludes are relevant to the foregoing determination.

In scheduling the Day-Ahead Energy Market, the following limitations shall apply:

(1) For purposes of satisfying the demand quantities for Day-Ahead Generation Contingency Reserve or Day-Ahead Replacement Energy Reserve specified in Sections III.1.8.5(a)-(e), the ISO shall not take into account an Energy Call Option Offer unless the Generator Asset or the Demand Response Resource associated with the Energy Call Option Offer meets the eligibility requirements enumerated in Section III.1.7.19.1.

(2) For purposes of satisfying the Day-Ahead Energy Imbalance Reserve Demand Quantity specified in Section III.1.8.5(f), the ISO shall not take into account an Energy Call Option Offer unless the Generator Asset or the Demand Response Resource associated with the Energy Call Option Offer is either (i) scheduled for energy in the Day-Ahead Energy Market for the applicable hour, or (ii) is a Fast Start Generator or Fast Start Demand Response Resource.

(b) Not later than 1:30 p.m. of the day before each Operating Day, or such earlier deadline as may be specified by the ISO in the ISO New England Manuals and ISO New England Administrative Procedures or such later deadline as necessary to account for software failures or other events, the ISO shall: (i) post the aggregate Day-Ahead Energy schedule; (ii) post the Day-Ahead Prices; and (iii) inform the Market Participants of their scheduled injections and withdrawals. In the event of an Emergency, the ISO will notify Market Participants as soon as practicable if the Day-Ahead Energy Market can-not be operated.

(c) Following posting of the information specified in Section III.1.10.8(b), the ISO shall revise its schedule of Resources to reflect updated projections of load, conditions affecting electric system operations in the New England Control Area, the availability of and constraints on limited energy and other Resources, transmission constraints, and other relevant factors. The ISO shall use its best efforts to determine the least-cost means to satisfy any remaining reliability requirements of the New England Control Area for the Operating Day.

(d) Market Participants shall pay and be paid for the quantities of energy scheduled in the Day-Ahead Energy Market at the applicable Day-Ahead Prices.

III.1.10.9 Hourly Scheduling.

(a) Following the initial posting by the ISO of the Locational Marginal Prices resulting from the Day-Ahead Energy Market, and subject to the right of the ISO to schedule and dispatch Resources and to direct that schedules be changed to address an actual or potential Emergency, a Resource Re-Offer Period shall exist from the time of the posting specified in Section III.1.10.8(b) until 2:00 p.m. on the day before each Operating Day or such other Re-Offer Period as necessary to account for software failures or other events. During the Re-Offer Period, Market Participants may submit revisions to Supply Offers, revisions to Demand Reduction Offers, and revisions to Demand Bids for any Dispatchable Asset Related Demand. Resources scheduled subsequent to the closing of the Re-Offer Period shall be settled at the applicable Real-Time Prices, and shall not affect the obligation to pay or receive payment for the quantities of energy scheduled in the Day-Ahead Energy Market at the applicable Day-Ahead Prices.

(b) During the Re-Offer Period, Market Participants may submit revisions to the price of priced External Transactions. External Transactions scheduled subsequent to the closing of the Re-Offer Period shall be settled at the applicable Real-Time Prices, and shall not affect the obligation to pay or receive payment for the quantities of energy scheduled in the Day-Ahead Energy Market at the applicable Day-

Ahead Prices. A submission during the Re-Offer Period for any portion of a transaction that was cleared in the Day-Ahead Energy Market is subject to the provisions in Section III.1.10.7. A Market Participant may request to Self-Schedule an External Transaction and adjust the schedule on an hour-to-hour basis or request to reduce the quantity of a priced External Transaction. The ISO must be notified of the request not later than 60 minutes prior to the hour in which the adjustment is to take effect. The External Transaction re-offer provisions of this Section III.1.10.9(b) shall not apply to Coordinated External Transactions, which are submitted pursuant to Section III.1.10.7.A.

(c) Following the completion of the initial Reserve Adequacy Analysis and throughout the Operating Day, a Market Participant may modify certain Supply Offer or Demand Bid parameters for a Generator Asset or a Dispatchable Asset Related Demand on an hour-to-hour basis, provided that the modification is made no later than 30 minutes prior to the beginning of the hour for which the modification is to take effect:

(i) For a Generator Asset, the Start-Up Fee, the No-Load Fee, the fuel type (for dual-fuel Generator Assets), and the quantity and price pairs of its Blocks may be modified.

(ii) For a Dispatchable Asset Related Demand, the quantity and price pairs of its Blocks may be modified.

(d) Following the completion of the initial Reserve Adequacy Analysis and throughout the Operating Day, a Market Participant may not modify any of the following Demand Reduction Offer parameters: price and demand reduction quantity pairs, Interruption Cost, Demand Response Resource Start-Up Time, Demand Response Resource Notification Time, Minimum Reduction Time, and Minimum Time Between Reductions.

(e) During the Operating Day, a Market Participant may request to Self-Schedule a Generator Asset or Dispatchable Asset Related Demand or may request to cancel a Self-Schedule for a Generator Asset or Dispatchable Asset Related Demand. The ISO will honor the request so long as it will not cause or worsen a reliability constraint. If the ISO is able to honor a Self-Schedule request, a Generator Asset will be permitted to come online at its Economic Minimum Limit and a Dispatchable Asset Related Demand will be dispatched to its Minimum Consumption Limit. A Market Participant may not request to Self-Schedule a Demand Response Resource. A Market Participant may cancel the Self-Schedule of a Continuous Storage Generator Asset or a Continuous Storage DARD only by declaring the facility unavailable.

(f) During the Operating Day, in the event that in a given hour a Market Participant seeks to modify a Supply Offer or Demand Bid after the deadline for modifications specified in Section III.1.10.9(c), then:

(i) the Market Participant may request that a Generator Asset be dispatched above its Economic Minimum Limit at a specified output. The ISO will honor the request so long as it will not cause or worsen a reliability constraint. If the ISO is able to honor the request, the Generator Asset will be dispatched as though it had offered the specified output for the hour in question at the Energy Offer Floor.

(ii) the Market Participant may request that a Dispatchable Asset Related Demand be dispatched above its Minimum Consumption Limit at a specified value. The ISO will honor the request so long as it will not cause or worsen a reliability constraint. If the ISO is able to honor the request, the Dispatchable Asset Related Demand will be dispatched at or above the requested amount for the hour in question.

(g) During the Operating Day, in any interval in which a Generator Asset is providing Regulation, the upper limit of its energy dispatch range shall be reduced by the amount of Regulation Capacity, and the lower limit of its energy dispatch range shall be increased by the amount of Regulation Capacity. Any such adjustment shall not affect the Real-Time Reserve Designation.

(h) During the Operating Day, in any interval in which a Continuous Storage ATRR is providing Regulation, the upper limit of the associated Generator Asset's energy dispatch range shall be reduced by the Regulation High Limit, and the associated DARD's consumption dispatch range shall be reduced by the Regulation Low Limit. Any such adjustment shall not affect the Real-Time Reserve Designation.

(i) For each hour in the Operating Day, as soon as practicable after the deadlines specified in the foregoing subsection of this Section III.1.10, the ISO shall provide Market Participants and parties to External Transactions with any revisions to their schedules for the hour.

III.1.11 Dispatch.

The following procedures and principles shall govern the dispatch of the Resources available to the ISO.

III.1.11.1 Resource Output or Consumption and Demand Reduction.

The ISO shall have the authority to direct any Market Participant to adjust the output, consumption or demand reduction of any Dispatchable Resource within the operating characteristics specified in the Market Participant's Offer Data, Supply Offer, Demand Reduction Offer or Demand Bid. The ISO may cancel its selection of, or otherwise release, Pool-Scheduled Resources. The ISO shall adjust the output, consumption or demand reduction of Resources as necessary: (a) for both Dispatchable Resources and Non-Dispatchable Resources, to maintain reliability, and subject to that constraint, for Dispatchable Resources, (b) to minimize the cost of supplying the energy, reserves, and other services required by the Market Participants and the operation of the New England Control Area; (c) to balance supply and demand, maintain scheduled tie flows, and provide frequency support within the New England Control Area; and (d) to minimize unscheduled interchange that is not frequency related between the New England Control Area and other Control Areas.

III.1.11.2 Operating Basis.

In carrying out the foregoing objectives, the ISO shall conduct the operation of the New England Control Area and shall, in accordance with the ISO New England Manuals and ISO New England Administrative Procedures, (i) utilize available Operating Reserve and replace such Operating Reserve when utilized; and (ii) monitor the availability of adequate Operating Reserve.

III.1.11.3 Dispatchable Resources.

With the exception of Settlement Only Resources, Generator Assets that meet the size criteria to be Settlement Only Resources, External Transactions, nuclear-powered Resources and photovoltaic Resources, all Resources must be Dispatchable Resources in the Energy Market and meet the technical specifications in ISO New England Operating Procedure No. 14 and ISO New England Operating Procedure No. 18 for dispatchability.

A Market Participant that does not meet the requirement for a Dispatchable Resource to be dispatchable in the Energy Market because the Resource is not connected to a remote terminal unit meeting the requirements of ISO New England Operating Procedure No. 18 shall take the following steps:

1. By January 15, 2017, the Market Participant shall submit to the ISO a circuit order form for the primary and secondary communication paths for the remote terminal unit.
2. The Market Participant shall work diligently with the ISO to ensure the Resource is able to receive and respond to electronic Dispatch Instructions within twelve months of the circuit order form submission.

A Market Participant that does not meet the requirement for a Dispatchable Resource to be dispatchable in the Energy Market by the deadline set forth above shall provide the ISO with a written plan for remedying the deficiencies, and shall identify in the plan the specific actions to be taken and a reasonable timeline for rendering the Resource dispatchable. The Market Participant shall complete the remediation in accordance with and under the timeline set forth in the written plan. Until a Resource is dispatchable, it may only be Self-Scheduled in the Real-Time Energy Market and shall otherwise be treated as a Non-Dispatchable Resource.

Dispatchable Resources in the Energy Market are subject to the following requirements:

(a) The ISO shall optimize the dispatch of energy from Limited Energy Resources by request to minimize the as-bid production cost for the New England Control Area. In implementing the use of Limited Energy Resources, the ISO shall use its best efforts to select the most economic hours of operation for Limited Energy Resources, in order to make optimal use of such Resources consistent with the dynamic load-following requirements of the New England Control Area and the availability of other Resources to the ISO.

(b) The ISO shall implement the dispatch of energy from Dispatchable Resources and the designation of Real-Time Operating Reserve to Dispatchable Resources, including the dispatchable portion of Resources which are otherwise Self-Scheduled, by sending appropriate signals and instructions to the entity controlling such Resources. Each Market Participant shall ensure that the entity controlling a Dispatchable Resource offered or made available by that Market Participant complies with the energy dispatch signals and instructions transmitted by the ISO.

(c) The ISO shall have the authority to modify a Market Participant's operational related Offer Data for a Dispatchable Resource if the ISO observes that the Market Participant's Resource is not operating in accordance with such Offer Data. The ISO shall modify such operational related Offer Data based on observed performance and such modified Offer Data shall remain in effect until either (i) the affected Market Participant requests a test to be performed, and coordinates the testing pursuant to the procedures specified in the ISO New England Manuals, and the results of the test justify a change to the Market Participant's Offer Data or (ii) the ISO observes, through actual performance, that modification to the Market Participant's Offer Data is justified.

(d) Market Participants shall exert all reasonable efforts to operate, or ensure the operation of, their Dispatchable Resources in the New England Control Area as close to dispatched output, consumption or demand reduction levels as practical, consistent with Good Utility Practice.

(e) Settlement Only Resources are not eligible to be DNE Dispatchable Generators.

Wind and hydro Intermittent Power Resources that are not Settlement Only Resources are required to receive and respond to Do Not Exceed Dispatch Points, except as follows:

(i) A wind or hydro Intermittent Power Resource not capable of receiving and responding to electronic Dispatch Instructions will be manually dispatched.

(ii) A Market Participant may elect, but is not required, to have a wind or hydro Intermittent Power Resource that is less than 5 MW and is connected through transmission facilities rated at less than 115 kV be dispatched as a DNE Dispatchable Generator.

(iii) A Market Participant with a hydro Intermittent Power Resource that is able to operate within a dispatchable range and is capable of responding to Dispatch Instructions to increase or decrease output within its dispatchable range may elect to have that resource dispatched as a DDP Dispatchable Resource.

(f) The ISO may request that dual-fuel Generator Assets that normally burn natural gas voluntarily take all necessary steps (within the limitations imposed by the operating limitations of their installed equipment and their environmental and operating permits) to prepare to switch to secondary fuel in anticipation of natural gas supply shortages. The ISO may request that Market Participants with dual-fuel Generator Assets that normally burn natural gas voluntarily switch to a secondary fuel in anticipation of natural gas supply shortages. The ISO may communicate with Market Participants with dual-fuel Generator Assets that normally burn natural gas to verify whether the Market Participants have switched or are planning to switch to an alternate fuel.

III.1.11.4 Emergency Condition.

If the ISO anticipates or declares an Emergency Condition, all External Transaction sales out of the New England Control Area that are not backed by a Resource may be interrupted, in accordance with the ISO New England Manuals, in order to serve load and Operating Reserve in the New England Control Area.

III.1.11.5 Dispatchability Requirements for Intermittent Power Resources.

(a) Intermittent Power Resources that are Dispatchable Resources with Supply Offers that do not clear in the Day-Ahead Energy Market and are not committed by the ISO prior to or during the Operating Day must be Self-Scheduled in the Real-Time Energy Market at the Resource's Economic Minimum Limit in order to operate in Real-Time.

(b) Intermittent Power Resources that are not Settlement Only Resources, are not Dispatchable Resources, and are not committed by the ISO prior to or during the Operating Day must be Self-Scheduled in the Real-Time Energy Market with the Resource's Economic Maximum Limit and Economic Minimum Limit redeclared to the same value in order to operate in Real-Time. Redeclarations must be updated throughout the Operating Day to reflect actual operating capabilities.

III.1.11.6 Non-Dispatchable Resources.

Non-Dispatchable Resources are subject to the following requirements:

(a) The ISO shall have the authority to modify a Market Participant's operational related Offer Data for a Non-Dispatchable Resource if the ISO observes that the Market Participant's Resource is not operating in accordance with such Offer Data. The ISO shall modify such operational related Offer Data based on observed performance and such modified Offer Data shall remain in effect until either (i) the affected Market Participant requests a test to be performed and coordinates the testing pursuant to the procedures specified in the ISO New England Manuals, and the results of the test justify a change to the Market Participant's Offer Data or (ii) the ISO observes, through actual performance, that modification to the Market Participant's Offer Data is justified.

(b) Market Participants with Non-Dispatchable Resources shall exert all reasonable efforts to operate or ensure the operation of their Resources in the New England Control Area as close to dispatched levels as practical when dispatched by the ISO for reliability, consistent with Good Utility Practice.

III.2 Day-Ahead Prices, Real-Time Prices, ~~LMPs~~ and Real-Time Reserve Clearing Prices Calculation

III.2.1 Introduction.

The ISO shall calculate the price of energy at Nodes, Load Zones, DRR Aggregation Zones and Hubs in the New England Control Area and at External Nodes on the basis of Locational Marginal Prices and shall calculate the price of Operating Reserve in Real-Time for each Reserve Zone on the basis of Real-Time Reserve Clearing Prices as determined in accordance with this Market Rule 1. Locational Marginal Prices for energy shall be calculated on a Day-Ahead basis for each hour of the Day-Ahead Energy Market, and every five minutes during the Operating Day for the Real-Time Energy Market. Real-Time Reserve Clearing Prices shall be calculated on a Real-Time basis every five minutes as part of the joint optimization of energy and Operating Reserve during the Operating Day. Commencing on June 1, 2024, Day-Ahead Ancillary Services prices and the Forecast Energy Requirement Price shall be calculated for each hour of the Operating Day, as specified in Section III.2.6.2, as part of the joint optimization of energy and ancillary services in the Day-Ahead Energy Market.

III.2.2 General.

The ISO shall determine the least cost security-constrained unit commitment and dispatch, which is the least costly means of serving load at different Locations in the New England Control Area based on scheduled or actual conditions, as applicable, existing on the power grid and on the prices at which Market Participants have offered to supply and consume energy in the New England Markets. Day-Ahead Locational Marginal Prices for energy for the applicable Locations will be calculated based on the unit commitment and economic dispatch and the prices of ~~energy~~ offers and bids. Real-Time Locational Marginal Prices for energy and Real-Time Reserve Clearing Prices will be calculated based on a jointly optimized economic dispatch of energy and designation of Operating Reserve utilizing the prices of energy offers and bids, and Reserve Constraint Penalty Factors as specified in Section III.2.7A when applicable. Commencing on June 1, 2024, Day-Ahead Locational Marginal Prices for energy, Day-Ahead Ancillary Services prices, and the Forecast Energy Requirement Price will be calculated based on a jointly optimized security-constrained economic commitment and dispatch of energy and Day-Ahead Ancillary Services utilizing the prices of offers and bids, and Reserve Constraint Penalty Factors as specified in Section III.2.6.2(b) when applicable.

Except as further provided in Section III.2.6, the process for the determination of Locational Marginal Prices shall be as follows:

(a) To determine operating conditions, in the Day-Ahead Energy Market or Real-Time Energy Market, on the New England Transmission System, the ISO shall use a computer model of the interconnected grid that uses scheduled quantities or available metered inputs regarding electric output, loads, and power flows to model remaining flows and conditions, producing a consistent representation of power flows on the network. The computer model employed for this purpose in the Real-Time Energy Market, referred to as the State Estimator program, is a standard industry tool and is described in Section III.2.3. It will be used to obtain information regarding the output of resources supplying energy and Operating Reserve to the New England Control Area, loads at busses in the New England Control Area, transmission losses, penalty factors, and power flows on binding transmission and interface constraints for use in the calculation of Day-Ahead and Real-Time Locational Marginal Prices and Real-Time Reserve Clearing Prices, and, commencing on June 1, 2024, Day-Ahead Ancillary Services prices and the Forecast Energy Requirement Price. Additional information used in the calculation of Real-Time Locational Marginal Prices and Real-Time Reserve Clearing Prices, including Offer Data, Real-Time Operating Reserve designations and Real-Time schedules for External Transactions, will be obtained from the ISO's dispatch software and dispatchers.

(b) Using the prices at which Market Participants offer and bid energy to the New England Markets, the ISO shall determine the offers and bids of energy that will be considered in the calculation of Day-Ahead Prices, Real-Time Prices and Real-Time Reserve Clearing Prices. During the Operating Day, Real-Time nodal Locational Marginal Prices and Real-Time Reserve Clearing Prices shall be determined every five minutes and such determinations shall be the basis of the settlement of sales and purchases of energy in the Real-Time Energy Market, the settlement associated with the provision of Operating Reserve in Real-Time and the settlement of Congestion Costs and costs for losses under the Transmission, Markets and Services Tariff not covered by the Day-Ahead Energy Market. As described in Section III.2.6, every offer and bid by a Market Participant that is scheduled in the Day-Ahead Energy Market will be utilized in the calculation of Day-Ahead Locational Marginal Prices.

III.2.3 Determination of System Conditions Using the State Estimator.

Power system operations, including, but not limited to, the determination of the least costly means of serving load and system and zonal Real-Time Operating Reserve requirements, depend upon the availability of a complete and consistent representation of generator outputs, loads, and power flows on the network. In calculating Day-Ahead Prices, the ISO shall base the system conditions on the expected transmission system configuration and the set of offers and bids submitted by Market Participants. In

calculating Real-Time Locational Marginal Prices and Real-Time Reserve Clearing Prices, the ISO shall obtain a complete and consistent description of conditions on the electric network in the New England Control Area by using the power flow solution produced by the State Estimator for the pricing interval, which is also used by the ISO for other functions within power system operations. The State Estimator is a standard industry tool that produces a power flow model based on available Real-Time metering information, information regarding the current status of lines, generators, transformers, and other equipment, bus load distribution factors, and a representation of the electric network, to provide a complete description of system conditions, including conditions at Nodes and External Nodes for which Real-Time information is unavailable. In calculating Real-Time Locational Marginal Prices and Real-Time Reserve Clearing Prices, the ISO shall obtain a State Estimator solution every five minutes, which shall provide the megawatt output of generators and the loads at Locations in the New England Control Area, transmission line losses, penalty factors, and actual flows or loadings on constrained transmission facilities. External Transactions between the New England Control Area and other Control Areas shall be included in the Real-Time Locational Marginal Price calculation on the basis of the Real-Time transaction schedules implemented by the ISO's dispatcher.

III.2.4 Adjustment for Rapid Response Pricing Assets.

For any Real-Time pricing interval during which a Rapid Response Pricing Asset is committed by the ISO, is in a dispatchable mode, and is not Self-Scheduled, the energy offer of that Rapid Response Pricing Asset shall be adjusted as described in this Section III.2.4 for purposes of the price calculations described in Section III.2.5 and Section III.2.7A. For purposes of the adjustment described in this Section III.2.4, if no Start-Up Fee, No-Load Fee, or Interruption Cost is specified in the submitted Offer Data, a value of zero shall be used; if no Minimum Run Time or Minimum Reduction Time is specified in the submitted Offer Data, or if the submitted Minimum Run Time or Minimum Reduction Time is less than 15 minutes, a duration of 15 minutes shall be used; and the energy offer after adjustment shall not exceed $2,000/MWh.

(a) If the Rapid Response Pricing Asset is a Fast Start Generator or a Flexible DNE Dispatchable Generator, its Economic Minimum Limit shall be set to zero; if the Rapid Response Pricing Asset is a Binary Storage DARD, its Minimum Consumption Limit shall be set to zero; if the Rapid Response Pricing Asset is a Fast Start Demand Response Resource, its Minimum Reduction shall be set to zero.

(b) If the Rapid Response Pricing Asset is a Fast Start Generator or a Flexible DNE Dispatchable Generator that has not satisfied its Minimum Run Time, its energy offer shall be increased by: (i) the

Start-Up Fee divided by the product of the Economic Maximum Limit and the Minimum Run Time; and (ii) the No-Load Fee divided by the Economic Maximum Limit.

(c) If the Rapid Response Pricing Asset is a Fast Start Generator or a Flexible DNE Dispatchable Generator that has satisfied its Minimum Run Time, its energy offer shall be increased by the No-Load Fee divided by the Economic Maximum Limit.

(d) If the Rapid Response Pricing Asset is a Fast Start Demand Response Resource that has not satisfied its Minimum Reduction Time, its energy offer shall be increased by the Interruption Cost divided by the product of the Maximum Reduction and the Minimum Reduction Time.

(e) If the Rapid Response Pricing Asset is a Fast Start Demand Response Resource that has satisfied its Minimum Reduction Time, its energy offer shall not be increased.

III.2.5 Calculation of Nodal Real-Time Prices.

(a) The ISO shall determine the least costly means of obtaining energy to serve the next increment of load at each Node internal to the New England Control Area represented in the State Estimator and each External Node Location between the New England Control Area and an adjacent Control Area, based on the system conditions described by the power flow solution produced by the State Estimator for the pricing interval. This calculation shall be made by applying an optimization method to minimize energy cost, given actual system conditions, a set of energy offers and bids (adjusted as described in Section III.2.4), and any binding transmission and Operating Reserve constraints that may exist. In performing this calculation, the ISO shall calculate the cost of serving an increment of load at each Node and External Node from all available Generator Assets (excluding Settlement Only Resources), Demand Response Resources, External Transaction purchases submitted under Section III.1.10.7 and Dispatchable Asset Related Demands with an eligible energy offer as the sum of: (1) the price at which the Market Participant has offered to supply or consume an additional increment of energy from the Resource; (2) the effect on Congestion Costs (whether positive or negative) associated with increasing the output of the Resource or reducing consumption of the Resource, based on the effect of increased output from that Resource or reduced consumption from that Resource on transmission line loadings; and (3) the effect on Congestion Costs (whether positive or negative) associated with increasing the Operating Reserve requirement, based on the effect of Resource re-dispatch on transmission line loadings; (4) the effect on Congestion Costs (whether positive or negative) associated with a deficiency in Operating Reserve, based on the effect of the Reserve Constraint Penalty Factors described under Section III.2.7A(c); and (5) the

effect on transmission losses caused by the increment of load, generation and demand reduction. The energy offer or offers and energy bid or bids that can jointly serve an increment of load and an increment of Operating Reserve requirement at a Location at the lowest cost, calculated in this manner, shall determine the Real-Time Price at that Node or External Node. For an external interface for which the enhanced scheduling procedures in Section III.1.10.7.A are implemented, the Real-Time Price at the External Node shall be further adjusted to include the effect on Congestion Costs (whether positive or negative) associated with a binding constraint limiting the external interface schedule, as determined when the interface is scheduled.

(b) During the Operating Day, the calculation set forth in this Section III.2.5 shall be performed for every five-minute interval, using the ISO's Locational Marginal Price program, producing a set of nodal Real-Time Prices based on system conditions during the pricing interval. The prices produced at five-minute intervals during an hour will be integrated to determine the nodal Real-Time Prices for that hour.

(c) For any interval during any hour in the Operating Day that the ISO has declared a Minimum Generation Emergency, the affected nodal Real-Time Prices calculated under this Section III.2.5 shall be set equal to the Energy Offer Floor for all Nodes within the New England Control Area and all External Nodes.

III.2.6 Calculation of ~~Nodal~~ Day-Ahead Prices.

III.2.6.1 Calculation of Day-Ahead Locational Marginal Prices.

(a) For the Day-Ahead Energy Market, Day-Ahead Locational Marginal Prices shall be determined on the basis of the least-cost, security-constrained unit commitment and dispatch, model flows and system conditions resulting from the load specifications submitted by Market Participants, Supply Offers, Demand Reduction Offers and Demand Bids for Resources, Increment Offers, Decrement Bids, ~~and~~ External Transactions, and, commencing on June 1, 2024, the Forecast Energy Requirement Demand Quantity, Day-Ahead Ancillary Service demand quantities, and Energy Call Option Offers submitted to the ISO and scheduled in the Day-Ahead Energy Market.

Such prices shall be determined in accordance with the provisions of this Section applicable to the Day-Ahead Energy Market and shall be the basis for the settlement of purchases and sales of energy, costs for losses and Congestion Costs resulting from the Day-Ahead Energy Market. This calculation shall be made for each hour in the Day-Ahead Energy Market by applying an optimization method to minimize

energy and, commencing on June 1, 2024, ancillary services cost, given scheduled system conditions, scheduled transmission outages, and any transmission limitations that may exist. In performing this calculation, the ISO shall calculate the cost of serving an increment of load at each Node and External Node from each Resource associated with an eligible energy offer, ~~or~~ energy bid, or Energy Call Option Offer as the sum of: (1) the price at which the Market Participant has offered to supply an additional increment of energy from the Resource or reduce consumption from the Resource and, commencing on June 1, 2024, the effect on ancillary service costs associated with increasing the output of the Resource or reducing consumption of the Resource; (2) the effect on transmission Congestion Costs (whether positive or negative) associated with increasing the output of the Resource or reducing consumption of the Resource, based on the effect of increased output from that Resource or reduced consumption from a Resource on transmission line loadings; and (3) the effect on transmission losses caused by the increment of load and supply. The energy offer or offers, Energy Call Option Offer or offers, and energy bid or bids that can serve an increment of load at a Node or External Node at the lowest cost, calculated in this manner, shall determine the Day-Ahead Locational Marginal Price at that Node.

For External Nodes for which the enhanced scheduling procedures in Section III.1.10.7.A are implemented, the clearing process specified in the previous two paragraphs shall apply. For all other External Nodes, the following process shall apply: in addition to determining the quantity cleared via the application of transmission constraints (i.e., limits on the flow over a line or set of lines), the quantity cleared is limited via the application of a nodal constraint (i.e., a limit on the total net injections at a Node) that restricts the net amount of cleared transactions to the transfer capability of the external interface. Clearing prices at all Nodes will reflect the marginal cost of serving the next increment of load at that Node while reflecting transmission constraints. A binding nodal constraint will result in interface limits being followed, but will not directly affect the congestion component of an LMP at an External Node.

(b) Energy deficient conditions. If the sum of Day-Ahead fixed Demand Bids and fixed External Transaction sales cannot be satisfied with the sum of all scheduled External Transaction purchases, cleared Increment Offers, and available supply at the Generator Asset's Economic Maximum Limit and demand reduction at the Demand Response Resource's Maximum Reduction, the technical software issues an Emergency Condition warning message due to a shortage of economic supply in the Day-Ahead Energy Market. The following steps shall then be performed to achieve power balance:

(i) All fixed External Transaction sales are considered to be dispatchable at the External Transaction Cap;

(ii) Reduce any remaining price-sensitive Demand Bids (including External Transaction sales) and Decrement Bids from lowest price to highest price to zero MW until power balance is achieved (there may be some price sensitive bids that are higher priced than the highest Supply Offer, Demand Reduction Offer, or Increment Offer price cleared). Set LMP values equal to the highest price-sensitive Demand Bid or Decrement Bid that was cut in this step. If no price-sensitive Demand Bid or Decrement Bid was reduced in this step, the LMP values are set equal to highest offer price of all on-line Generator Assets, dispatched Demand Response Resources, Increment Offers or External Transaction purchases; and

(iii) If power balance is not achieved after step (ii), reduce all remaining fixed Demand Bids proportionately (by ratio of load MW) until balance is achieved. Set LMP values equal to the highest offer price of all on-line Generator Assets (excluding Settlement Only Resources), dispatched Demand Response Resources, Increment Offers or External Transaction purchases or the price from step (ii), whichever is higher.

(c) Excess energy conditions. If the sum of Day-Ahead cleared Demand Bids, Decrement Bids and External Transaction sales is less than the total system wide supply (including fixed External Transaction purchases) with all possible Generator Assets off line and with all remaining Generator Assets at their Economic Minimum Limit, the technical software issues a Minimum Generation Emergency warning message due to an excess of economic supply in the Day-Ahead Energy Market. The following steps shall then be performed to achieve power balance:

(i) All fixed External Transaction purchases are considered to be dispatchable at the Energy Offer Floor and reduced pro-rata, as applicable, until power balance is reached;

(ii) If power balance is not reached in step (i), reduce all committed Generator Assets down proportionately by ratio of Economic Minimum Limits, but not below Emergency Minimum Limits. If power balance is achieved prior to reaching Emergency Minimum Limits, set LMP values equal to the lowest offer price of all on-line Generator Assets (excluding Settlement Only Resources); and

(iii) If power balance not achieved in step (ii), set LMP values to Energy Offer Floor and reduce all Generator Assets generation below Emergency Minimum Limits proportionately (by ratio of Emergency Minimum Limits) to achieve power balance.

III.2.6.2 Calculation of Additional Day-Ahead Prices.

(a) Commencing on June 1, 2024, the ISO shall calculate hourly Day-Ahead Prices for additional requirements in the Day-Ahead Energy Market as described in this Section III.2.6.2(a).

(i) The clearing price for Day-Ahead Four-Hour Reserve shall be the incremental cost, as measured by the change in the Day-Ahead Energy Market's security-constrained economic dispatch objective value, to satisfy the next increment of the Day-Ahead Total Four-Hour Reserve Demand Quantity.

(ii) The clearing price for Day-Ahead Ninety-Minute Reserve shall be the sum of (a) the incremental cost, as measured by the change in the Day-Ahead Energy Market's security-constrained economic dispatch objective value, to satisfy the next increment of the Day-Ahead Total Ninety-Minute Reserve Demand Quantity, and (b) the clearing price for Day-Ahead Four-Hour Reserve.

(iii) The clearing price for Day-Ahead Thirty-Minute Operating Reserve shall be the sum of (a) the incremental cost, as measured by the change in the Day-Ahead Energy Market's security-constrained economic dispatch objective value, to satisfy the next increment of the Day-Ahead Total Thirty-Minute Operating Reserve Demand Quantity, and (b) the clearing price for Day-Ahead Ninety-Minute Reserve.

(iv) The clearing price for Day-Ahead Ten-Minute Non-Spinning Reserve shall be the sum of (a) the incremental cost, as measured by the change in the Day-Ahead Energy Market's security-constrained economic dispatch objective value, to satisfy the next increment of the Day-Ahead Total Ten-Minute Reserve Demand Quantity, and (b) the clearing price for Day-Ahead Thirty-Minute Operating Reserve.

(v) The clearing price for Day-Ahead Ten-Minute Spinning Reserve shall be the sum of (a) the incremental cost, as measured by the change in the Day-Ahead Energy Market's security-constrained economic dispatch objective value, to satisfy the next increment of the Day-Ahead

Ten-Minute Spinning Reserve Demand Quantity, and (b) the clearing price for Day-Ahead Ten-Minute Non-Spinning Reserve.

(vi) The clearing price for Day-Ahead Energy Imbalance Reserve shall be the Forecast Energy Requirement Price.

(vii) The Forecast Energy Requirement Price shall be the marginal cost, as measured by the change in the Day-Ahead Energy Market's security-constrained economic dispatch objective value, to satisfy the next increment of the Forecast Energy Requirement Demand Quantity.

(b) **Reserve Constraint Penalty Factors.** The Day-Ahead Energy Market scheduling pursuant to Section III.1.10.8(a)(ii), and the Day-Ahead Prices specified in Section III.2.6, shall respect the applicable Reserve Constraint Penalty Factors specified below:

(i) The Reserve Constraint Penalty Factor applicable to the Day-Ahead Ten-Minute Spinning Reserve Demand Quantity shall be equal to the Real-Time Ten-Minute Spinning Reserve Requirement Reserve Constraint Penalty Factor specified in Section III.2.7A.

(ii) The Reserve Constraint Penalty Factor applicable to the Day-Ahead Total Ten-Minute Reserve Demand Quantity shall be equal to the Real-Time Ten-Minute Reserve Requirement Reserve Constraint Penalty Factor specified in Section III.2.7A.

(iii) The Reserve Constraint Penalty Factor applicable to the Day-Ahead Total Thirty-Minute Operating Reserve Demand Quantity shall be equal to the Real-Time Minimum Total Reserve Requirement Reserve Constraint Penalty Factor specified in Section III.2.7A.

(iv) The Reserve Constraint Penalty Factor applicable to the Day-Ahead Total Ninety-Minute Reserve Demand Quantity shall be equal to $250/MWh.

(v) The Reserve Constraint Penalty Factor applicable to the Day-Ahead Total Four-Hour Reserve Demand Quantity shall be equal to $100/MWh.

(vi) The Reserve Constraint Penalty Factor applicable to the Forecast Energy Requirement Demand Quantity shall be set at 101% of the sum of the Reserve Constraint Penalty Factors in Sections III.2.6.2(b)(i)-(v).

III.2.7 Reliability Regions, Load Zones, Reserve Zones, Zonal Prices and External Nodes.

(a) The ISO shall calculate Zonal Prices for each Load Zone and DRR Aggregation Zone for both the Day-Ahead Energy Market and Real-Time Energy Markets using a load-weighted average of the Locational Marginal Prices for the Nodes within that Load Zone or DRR Aggregation Zone. The load weights used in calculating the Day-Ahead Zonal Prices for the Load Zone and DRR Aggregation Zone shall be determined in accordance with applicable Market Rule 1 provisions and shall be based on historical load usage patterns. The load weights do not reflect Demand Bids or Decrement Bids that settle at the Node level in the Day-Ahead Energy Market. The ISO shall determine, in accordance with applicable ISO New England Manuals, the load weights used in Real-Time based on the actual Real-Time load distribution as calculated by the State Estimator, and shall exclude any Asset Related Demand from the load weights used to calculate the applicable Real-Time Zonal Prices.

(b) Each Load Zone shall initially be approximately coterminous with a Reliability Region.

(c) Reserve Zones shall be established by the ISO which represent areas within the New England Transmission System that require local 30 minute contingency response as part of normal system operations in order to satisfy local 2nd contingency response reliability criteria.

(d) The remaining area within the New England Transmission System that is not included within the Reserve Zones established under Section III.2.7(c) is Rest of System.

(e) Each Reserve Zone shall be completely contained within a Load Zone or shall be defined as a subset of the Nodes contained within a Load Zone.

(f) The ISO shall calculate Forward Reserve Clearing Prices and Real-Time Reserve Clearing Prices for each Reserve Zone.

(g) After consulting with the Market Participants, the ISO may reconfigure Reliability Regions, Load Zones, Dispatch Zones, and Reserve Zones and add or subtract Reliability Regions, Load Zones, Dispatch

Zones, and Reserve Zones as necessary over time to reflect changes to the grid, patterns of usage, changes in local TMOR contingency response requirements and intrazonal Congestion. The ISO shall file any such changes with the Commission.

(h) In the event the ISO makes changes to a Reliability Region or Load Zone or adds or subtracts Reliability Regions and Load Zones, for settlement purposes and to the extent practicable, Load Assets that are physically located in one Reliability Region and electrically located within another Reliability Region shall be located within the Reliability Region to which they are electrically located.

(i) External Nodes are the nodes at which External Transactions settle. As appropriate and after consulting with Market Participants, the ISO will establish and re-configure External Nodes taking into consideration appropriate factors, which may include: tie line operational matters, FTR modeling and auction assumptions, market power issues associated with external contractual arrangements, impacts on Locational Marginal Prices, and inter-regional trading impacts.

(j) On or about the 20th calendar day of each month, the ISO shall publish the Real-Time nodal load weights (expressed in MW) used to calculate the load-weighted Real-Time Zonal Prices for the preceding month. Nodal load weights will be published for all nodes used in the calculations except for those nodes identified by customers as nodes for which publication would provide individual customer usage data. Any individual customer whose usage data would be revealed by publication of load weight information associated with a specific Node must submit a written request to the ISO to omit the applicable Node from the publication requirement. The request must identify the affected Node and, to the best of the customer’s knowledge, the number of customers taking service at the affected Node and the estimated percentage of the total annual load (MWh) at the affected Node period that is attributable to the customer. The information contained in the request must be certified in writing by an officer of the customer’s company (if applicable), by an affidavit signed by a person having knowledge of the applicable facts, or by representation of counsel for the customer. The ISO will grant a customer request if it determines based on the information provided that no more than two customers are taking service at the affected Node or that the percentage of the customer’s annual load (MWh) at the affected Node is greater than 75 percent of the total load (MWh) at the affected Node. If a customer request is granted and that customer request is the only such customer request within a Load Zone, then the ISO shall randomly select one other Node and not disclose hourly load information for the randomly selected Node unless and until another customer request within the Load Zone is granted. A request to suspend publication for a month must be received by the ISO on or before the 10th calendar day of the following month in order to be

effective for that month. Upon receipt of a request, the ISO will suspend publication of the load weight data for the specified Node. The ISO may, from time to time, require customer confirmation that continued omission from publication of load weight data for a particular Node is required in order to avoid disclosure of individual customer usage data. If customer confirmation is not received within a reasonable period not to exceed 30 days, the ISO may publish load weight data for the applicable Node.

III.2.7A Calculation of Real-Time Reserve Clearing Prices.

(a) The ISO shall obtain Operating Reserve in Real-Time to serve Operating Reserve requirements for the system and each Reserve Zone on a jointly optimized basis with the calculation of nodal Real-Time Prices specified under Section III.2.5, based on the system conditions described by the power flow solution produced by the State Estimator program for the pricing interval. This calculation shall be made by applying an optimization method to maximize social surplus, given actual system conditions, a set of energy offers and bids, and any binding transmission constraints, including binding transmission interface constraints associated with meeting Operating Reserve requirements, and binding Operating Reserve constraints that may exist. In performing this calculation, the ISO shall calculate, on a jointly optimized basis with serving an increment of load at each Node and External Node, the cost of serving an increment of Operating Reserve requirement for the system and each Reserve Zone from all available Generator Assets (excluding Settlement Only Resources), Demand Response Resources and Dispatchable Asset Related Demands with an eligible energy offer or bid. Real-Time Reserve Clearing Prices will be equal to zero unless system re-dispatch is required in order to meet the system and zonal Operating Reserve requirements or there is a deficiency in available Operating Reserve, in which case Real-Time Reserve Clearing Prices shall be set as described in Section III.2.7A(b) and Section III.2.7A(c).

(b) If system re-dispatch is required to maintain sufficient levels of Operating Reserve, the applicable Real-Time Reserve Clearing Price is equal to the highest unit-specific Real-Time Reserve Opportunity Cost associated with all Generator Assets, Demand Response Resources and Dispatchable Asset Related Demands that were re-dispatched to meet the applicable Operating Reserve requirement. The Real-Time Reserve Opportunity Cost of a Resource shall be equal to the difference between (i) the Real-Time Energy LMP at the Location for the Resource and (ii) the offer price associated with the re-dispatch of the Resource necessary to create the additional Operating Reserve.

(c) If there is insufficient Operating Reserve available to meet the Operating Reserve requirements for the system and/or any Reserve Zone or sufficient Operating Reserve is not available at a redispatch

cost equal to or less than that specified by the Reserve Constraint Penalty Factors, the applicable Real-Time Reserve Clearing Prices shall be set based upon the following Reserve Constraint Penalty Factors:

Real-Time Requirement	**Reserve Constraint Penalty Factor**
Zonal Reserve Requirement (combined amount of TMSR, TMNSR, and TMOR required for a Reserve Zone)	$250/MWh
Minimum Total Reserve Requirement (does not include Replacement Reserve) (combined amount of TMSR, TMNSR, and TMOR required system-wide)	$1000/MWh
Total Reserve Requirement (includes Replacement Reserve) (combined amount of TMSR, TMNSR, and TMOR required system-wide)	$250/MWh
Ten-Minute Reserve Requirement (combined amount of TMSR and TMNSR required system-wide)	$1500/MWh
Ten-Minute Spinning Reserve Requirement (amount of TMSR required system-wide)	$50/MWh

The Reserve Constraint Penalty Factors shall be applied in a manner that is consistent with the price cascading described in Section III.2.7A(d).

(d) Real-Time Reserve designations and Real-Time Reserve Clearing Prices shall be calculated in such a manner to ensure that excess Real-Time Operating Reserve capability will cascade down for use in meeting any remaining Real-Time Operating Reserve requirements from TMSR to TMNSR to TMOR and that the pricing of Real-Time Operating Reserve shall cascade up from TMOR to TMNSR to TMSR.

(e) During the Operating Day, the calculation set forth in this Section III.2.7A shall be performed for every five-minute interval, using the ISO's Unit Dispatch System and Locational Marginal Price program, producing a set of zonal Real-Time Reserve Clearing Prices based on system conditions for the pricing interval. The prices produced at five-minute intervals during an hour will be integrated to determine the Real-Time Reserve Clearing Prices for the system and/or each Reserve Zone for that hour.

III.2.8 Hubs and Hub Prices.

(a) On behalf of the Market Participants, the ISO shall maintain and facilitate the use of a Hub or Hubs for the Day-Ahead Energy Market and Real-Time Energy Market, comprised of a set of Nodes

within the New England Control Area, which Nodes shall be identified by the ISO on its internet website. The ISO has used the following criteria to establish an initial Hub and shall use the same criteria to establish any additional Hubs:

(i) Each Hub shall contain a sufficient number of Nodes to try to ensure that a Hub Price can be calculated for that Hub at all times;

(ii) Each Hub shall contain a sufficient number of Nodes to ensure that the unavailability of, or an adjacent line outage to, any one Node or set of Nodes would have only a minor impact on the Hub Price;

(iii) Each Hub shall consist of Nodes with a relatively high rate of service availability;

(iv) Each Hub shall consist of Nodes among which transmission service is relatively unconstrained; and

(v) No Hub shall consist of a set of Nodes for which directly connected load and/or generation at that set of Nodes is dominated by any one entity or its Affiliates.

(b) The ISO shall calculate and publish Hub Prices for both the Day-Ahead and Real-Time Energy Markets based upon the arithmetic average of the Locational Marginal Prices of the nodes that comprise the Hub.

III.2.9A Final Real Time Prices, Real-Time Reserve Clearing and Regulation Clearing Prices.

(a) The ISO normally will post provisional Real-Time Prices, Real-Time Reserve Clearing Prices and Regulation clearing prices in Real-Time or soon thereafter. The ISO shall post the final Real-Time Prices, final Real-Time Reserve Clearing Prices and final Regulation clearing prices as soon as practicable following the Operating Day, in accordance with the timeframes specified in the ISO New England Manuals, except that the posting of such final Real-Time Prices, final Real-Time Reserve Clearing Prices and final Regulation clearing prices by the ISO shall not exceed five business days from the applicable Operating Day. If the ISO is not able to calculate Real-Time Prices, Real-Time Reserve Clearing Prices or Regulation clearing prices normally due to human error, hardware, software, or telecommunication problems that cannot be remedied in a timely manner, the ISO will calculate Real-

Time Prices, Real-Time Reserve Clearing Prices or Regulation clearing prices as soon as practicable using the best data available; provided, however, in the event that the ISO is unable to calculate and post final Real-Time Prices, Real-Time Reserve Clearing Prices or Regulation clearing prices due to exigent circumstances not contemplated in this market rule, the ISO shall make an emergency filing with the Commission within five business days from the applicable Operating Day detailing the exigent circumstance, which will not allow the final clearing prices to be calculated and posted, along with a proposed resolution including a timeline to post final clearing prices.

(b) The permissibility of correction of errors in Real-Time Prices, Real-Time Reserve Clearing Prices or Regulation clearing prices for an Operating Day due to database, software or similar errors of the ISO or its systems, and the timeframes and procedures for permitted corrections, are addressed solely in this Section III.2.9A and not in those sections of Market Rule 1 relating to settlement and billing processes.

III.2.9B Final Day-Ahead Energy Market Results

(a) Day-Ahead Energy Market results are final when published except as provided in this subsection. If the ISO determines based on reasonable belief that there may be one or more errors in the Day-Ahead Energy Market results for an Operating Day or if no Day-Ahead Energy Market results are available due to human error, database, software or similar errors of the ISO or its systems, the ISO shall post on the ISO website prior to 12:01 a.m. of the applicable Operating Day, a notice that the results are provisional and subject to correction or unavailable for initial publishing. Any Day-Ahead Energy Market results for which no notice is posted shall be final and not subject to correction or other adjustment, and shall be used for purposes of settlement. The ISO shall confirm within three business days of the close of the applicable Operating Day whether there was an error in any provisional Day-Ahead Energy Market results and shall post a notice stating its findings.

(b) The ISO will publish corrected Day-Ahead Energy Market results within three business days of the close of the applicable Operating Day or the results of the Day-Ahead Energy Market for the Operating Day will stand; provided, however, in the event that the ISO is unable to calculate and post final Day-Ahead Energy Market Results due to exigent circumstances not contemplated in this market rule, the ISO shall make an emergency filing with the Commission within five business days from the applicable Operating Day detailing the exigent circumstance, which will not allow the final prices to be calculated and posted, along with a proposed resolution including a timeline to post final prices. The ISO shall also publish a statement describing the nature of the error and the method used to correct the results.

(c) If the ISO determines in accordance with subsection (a) that there are one or more errors in the Day-Ahead Energy Market results for an Operating Day, the ISO shall calculate corrected Day-Ahead Energy Market results by determining and substituting for the initial results, final results that reasonably reflect how the results would have been calculated but for the errors. To the extent that it is necessary, reasonable and practicable to do so, the ISO may specify an allocation of any costs that are not otherwise allocable under applicable provisions of Market Rule 1. The ISO shall use the corrected results for purposes of settlement.

(d) For every change in the Day-Ahead Energy Market results made pursuant to Section III.2.9B, the ISO will prepare and submit, as soon as practicable, an informational report to the Commission describing the nature of any errors, the precise remedy administered, the method of determining corrected prices and allocating any costs, and any remedial actions that will be taken to avoid similar errors in the future.

(e) The permissibility of correction of errors in Day-Ahead Energy Market results, and the timeframes and procedures for permitted corrections, are addressed solely in this Section III.2.9B and not in those sections of Market Rule 1 relating to settlement and billing processes.

III.3 Accounting And Billing

III.3.1 Introduction.

This Section III.3 sets forth the accounting and billing principles and procedures for the purchase and sale of services in the New England Markets and for the operation of the New England Control Area.

If a dollar-per-MW-hour value is applied in a calculation where the interval of the value produced in that calculation is less than an hour, then for purposes of that calculation the dollar-per-MW-hour value is divided by the number of intervals in the hour.

III.3.2 Market Participants.

III.3.2.1 ISO Energy Market.

For purposes of establishing the following positions, unless otherwise expressly stated, the settlement interval for the Real-Time Energy Market is five minutes and the settlement interval for the Day-Ahead Energy Market is hourly. The Real-Time Energy Market settlement is determined using the Metered Quantity For Settlement calculated in accordance with Section III.3.2.1.1.

(a)(1) **Day-Ahead Energy Market Energy Obligations** – For each Market Participant for each settlement interval, the ISO will determine a Day-Ahead Energy Market position representing that Market Participant's net purchases from or sales to the Day-Ahead Energy Market as follows:

(i) **Day-Ahead Load Obligation** – Each Market Participant shall have for each settlement interval a Day-Ahead Load Obligation for energy at each Location equal to the MWhs of its Demand Bids, Decrement Bids and External Transaction sales accepted by the ISO in the Day-Ahead Energy Market at that Location and such Day-Ahead Load Obligation shall have a negative value.

(ii) **Day-Ahead Generation Obligation** – Each Market Participant shall have for each settlement interval a Day-Ahead Generation Obligation for energy at each Location equal to the MWhs of its Supply Offers, Increment Offers and External Transaction purchases accepted by the ISO in the Day-Ahead Energy Market at that Location and such Day-Ahead Generation Obligation shall have a positive value.

(iii) **Day-Ahead Demand Reduction Obligation** – Each Market Participant shall have for each settlement interval a Day-Ahead Demand Reduction Obligation at each Location equal to the MWhs of its Demand Reduction Offers accepted by the ISO in the Day-Ahead Energy Market at that Location, increased by average avoided peak distribution losses. Day-Ahead Demand Reduction Obligations shall have a positive value.

(iv) **Day-Ahead Adjusted Load Obligation** – Each Market Participant shall have for each settlement interval a Day-Ahead Adjusted Load Obligation at each Location equal to the Day-Ahead Load Obligation adjusted by any applicable Day-Ahead internal bilateral transactions at that Location.

(v) **Day-Ahead Locational Adjusted Net Interchange** – Each Market Participant shall have for each settlement interval a Day-Ahead Locational Adjusted Net Interchange at each Location equal to the Day-Ahead Adjusted Load Obligation plus the Day-Ahead Generation Obligation plus the Day-Ahead Demand Reduction Obligation at that Location.

(a)(2) **Day-Ahead Energy Market Ancillary Services Obligations** – Commencing on June 1, 2024, each Market Participant with an Energy Call Option Offer that is accepted by the ISO in the Day-Ahead Energy Market shall have for each settlement interval a Day-Ahead Ancillary Services obligation as follows:

(i) **Day-Ahead Ten-Minute Spinning Reserve Obligation** – A Market Participant with an accepted Energy Call Option Offer quantity that contributes to satisfying the Day-Ahead Ten-Minute Spinning Reserve Demand Quantity shall receive a Day-Ahead Ten-Minute Spinning Reserve Obligation.

(ii) **Day-Ahead Ten-Minute Non-Spinning Reserve Obligation** – A Market Participant with an accepted Energy Call Option Offer quantity that contributes to satisfying the Day-Ahead Total Ten-Minute Reserve Demand Quantity, and that same Energy Call Option Offer quantity does not receive a Day-Ahead Ten-Minute Spinning Reserve Obligation, shall receive a Day-Ahead Ten-Minute Non-Spinning Reserve Obligation.

(iii) **Day-Ahead Thirty-Minute Operating Reserve Obligation** – A Market Participant with an accepted Energy Call Option Offer quantity that contributes to satisfying the Day-Ahead Total

Thirty-Minute Operating Reserve Demand Quantity, and that same Energy Call Option Offer quantity does not receive either a Day-Ahead Ten-Minute Spinning Reserve Obligation or a Day-Ahead Ten-Minute Non-Spinning Reserve Obligation, shall receive a Day-Ahead Thirty-Minute Operating Reserve Obligation.

(iv) **Day-Ahead Ninety-Minute Reserve Obligation** – A Market Participant with an accepted Energy Call Option Offer quantity that contributes to satisfying the Day-Ahead Total Ninety-Minute Reserve Demand Quantity, and that same Energy Call Option Offer quantity does not receive a Day-Ahead Ten-Minute Spinning Reserve Obligation, a Day-Ahead Ten-Minute Non-Spinning Reserve Obligation, or a Day-Ahead Thirty-Minute Operating Reserve Obligation, shall receive a Day-Ahead Ninety-Minute Reserve Obligation.

(v) **Day-Ahead Four-Hour Reserve Obligation** – A Market Participant with an accepted Energy Call Option Offer quantity that contributes to satisfying the Day-Ahead Total Four-Hour Reserve Demand Quantity, and that same Energy Call Option Offer quantity does not receive a Day-Ahead Ten-Minute Spinning Reserve Obligation, a Day-Ahead Ten-Minute Non-Spinning Reserve Obligation, a Day-Ahead Thirty-Minute Operating Reserve Obligation, or a Day-Ahead Ninety-Minute Reserve Obligation, shall receive a Day-Ahead Four-Hour Reserve Obligation.

(vi) **Day-Ahead Energy Imbalance Reserve Obligation** – A Market Participant with an accepted Energy Call Option Offer quantity that contributes to satisfying the Forecast Energy Requirement Demand Quantity shall receive a Day-Ahead Energy Imbalance Reserve Obligation.

(b) **Real-Time Energy Market Obligations Excluding Demand Response Resource Contributions** – For each Market Participant for each settlement interval, the ISO will determine a Real-Time Energy Market position. For purposes of these calculations, if the settlement interval is less than one hour, any internal bilateral transaction shall be equally apportioned over the settlement intervals within the hour. To accomplish this, the ISO will perform calculations to determine the following:

(i) **Real-Time Load Obligation** – Each Market Participant shall have for each settlement interval a Real-Time Load Obligation for energy at each Location equal to the MWhs of load, where such MWhs of load shall include External Transaction sales and shall have a negative value, at that Location, adjusted for unmetered load and any applicable internal bilateral transactions which transfer Real-Time load obligations.

(ii) **Real-Time Generation Obligation** – Each Market Participant shall have for each settlement interval a Real-Time Generation Obligation for energy at each Location. The Real-Time Generation Obligation shall equal the MWhs of energy, where such MWhs of energy shall have positive value, provided by Generator Assets and External Transaction purchases at that Location.

(iii) **Real-Time Adjusted Load Obligation** – Each Market Participant shall have for each settlement interval a Real-Time Adjusted Load Obligation at each Location equal to the Real-Time Load Obligation adjusted by any applicable energy related internal Real-Time bilateral transactions at that Location.

(iv) **Real-Time Locational Adjusted Net Interchange –** Each Market Participant shall have for each settlement interval a Real-Time Locational Adjusted Net Interchange at each Location equal to the Real-Time Adjusted Load Obligation plus the Real-Time Generation Obligation at that Location.

(v) **Marginal Loss Revenue Load Obligation –** Each Market Participant shall have for each settlement interval a Marginal Loss Revenue Load Obligation at each Location equal to the Real-Time Load Obligation adjusted by any energy related internal Real-Time bilateral transactions at that Location that the parties to those bilateral transactions have elected to include in their Marginal Loss Revenue Load Obligation for the purpose of allocating Day-Ahead Loss Revenue and Real-Time Loss Revenue. Contributions from Coordinated External Transactions shall be excluded from the Real-Time Load Obligation for purposes of determining Marginal Loss Revenue Load Obligation.

(c) **<u>Real-Time Energy Market Obligations For Demand Response Resources</u>**

Real-Time Demand Reduction Obligation – Each Market Participant shall have for each settlement interval a Real-Time Demand Reduction Obligation at each Location equal to the MWhs of demand reduction provided by Demand Response Resources at that Location in response to non-zero Dispatch Instructions. The MWhs of demand reduction produced by a Demand Response Resource are equal to the sum of the demand reductions produced by its constituent Demand Response Assets calculated pursuant to Section III.8.4, where the demand reductions, other than MWhs associated with Net Supply, are increased by average avoided peak distribution losses.

(d) **Real-Time Energy Market Deviations Excluding Demand Response Resource Contributions** – For each Market Participant for each settlement interval, the ISO will determine the difference between the Real-Time Energy Market position (calculated in accordance with Section III.3.2.1(b)) and the Day-Ahead Energy Market position (calculated in accordance with Section III.3.2.1(a)(1)) representing that Market Participant's net purchases from or sales to the Real-Time Energy Market (excluding any such transactions involving Demand Response Resources). For purposes of this calculation, if the Real-Time settlement interval is less than one hour, the Day-Ahead position shall be equally apportioned over the settlement intervals within the hour. To accomplish this, the ISO will perform calculations to determine the following:

(i) **Real-Time Load Obligation Deviation** – Each Market Participant shall have for each settlement interval a Real-Time Load Obligation Deviation at each Location equal to the difference in MWhs between the Real-Time Load Obligation and the Day-Ahead Load Obligation.

(ii) **Real-Time Generation Obligation Deviation** – Each Market Participant shall have for each settlement interval a Real-Time Generation Obligation Deviation at each Location equal to the difference in MWhs between the Real-Time Generation Obligation and the Day-Ahead Generation Obligation.

(iii) **Real-Time Adjusted Load Obligation Deviation** – Each Market Participant shall have for each settlement interval a Real-Time Adjusted Load Obligation Deviation at each Location equal to the difference in MWhs between the Real-Time Adjusted Load Obligation and the Day-Ahead Adjusted Load Obligation.

(iv) **Real-Time Locational Adjusted Net Interchange Deviation** – Each Market Participant shall have for each settlement interval a Real-Time Locational Adjusted Net Interchange Deviation at each Location equal to the difference in MWhs between (1) the Real-Time Locational Adjusted Net Interchange and (2) the Day-Ahead Locational Adjusted Net Interchange minus the Day-Ahead Demand Reduction Obligation for that Location.

(e) **Real-Time Energy Market Deviations For Demand Response Resources**

Real-Time Demand Reduction Obligation Deviation – Each Market Participant shall have for each settlement interval a Real-Time Demand Reduction Obligation Deviation at each Location equal to the difference in MWhs between the Real-Time Demand Reduction Obligation (calculated in accordance with Section III.3.2.1(c)) and the Day-Ahead Demand Reduction Obligation (calculated in accordance with Section III.3.2.1(a)(1)). For purposes of this calculation, if the Real-Time settlement interval is less than one hour, the Day-Ahead position shall be equally apportioned over the settlement intervals within the hour.

(f) **Day-Ahead Energy Market Energy Charge/Credit** – For each Market Participant for each settlement interval, the ISO will determine Day-Ahead Energy Market monetary positions representing a charge or credit for its net purchases from or sales to the ISO Day-Ahead Energy Market. The Day-Ahead Energy Market Energy Charge/Credit shall be equal to the sum of its Location specific Day-Ahead Locational Adjusted Net Interchanges multiplied by the Energy Component of the associated Day-Ahead Locational Marginal Prices. The Day-Ahead Energy Market Congestion Charge/Credit shall be equal to the sum of its Location specific Day-Ahead Locational Adjusted Net Interchanges multiplied by the Congestion Component of the associated Day-Ahead Locational Marginal Prices. The Day-Ahead Energy Market Loss Charge/Credit shall be equal to the sum of its Location specific Day-Ahead Locational Adjusted Net Interchanges multiplied by the Loss Component of the associated Day-Ahead Locational Marginal Prices.

(g) **Real-Time Energy Market Charge/Credit Excluding Demand Response Resources** – For each Market Participant for each settlement interval, the ISO will determine Real-Time Energy Market monetary positions representing a charge or credit to the Market Participant for its net purchases from or sales to the Real-Time Energy Market (excluding any such transactions involving Demand Response Resources). The Real-Time Energy Market Deviation Energy Charge/Credit shall be equal to the sum of the Market Participant's Location specific Real-Time Locational Adjusted Net Interchange Deviations for that settlement interval multiplied by the Energy Component of the Real-Time Locational Marginal Prices. The Real-Time Energy Market Deviation Congestion Charge/Credit shall be equal to the sum of the Market Participant's Location specific Real-Time Locational Adjusted Net Interchange Deviations for that settlement interval multiplied by the Congestion Component of the associated Real-Time Locational Marginal Prices. The Real-Time Energy Market Deviation Loss Charge/Credit shall be equal to the sum of the Market Participant's Location specific Real-Time Locational Adjusted Net Interchange Deviations for that settlement interval multiplied by the Loss Component of the associated Real-Time Locational Marginal Prices.

(h) **Real-Time Energy Market Charge/Credit For Demand Response Resources** – For each Market Participant for each settlement interval, the ISO shall calculate a charge or credit to the Market Participant for its net purchases from or sales to the Real-Time Energy Market associated with Demand Response Resources. The charge or credit shall be equal to the sum of the Market Participant's Location-specific Real-Time Demand Reduction Obligation Deviations for that settlement interval multiplied by the Real-Time Locational Marginal Prices. Such charges and credits shall be allocated on an hourly basis to Market Participants based on their pro rata share of the sum of all Market Participants' Real-Time Load Obligation, excluding the Real-Time Load Obligation incurred at all External Nodes, and excluding Real-Time Load Obligation incurred by Storage DARDs.

(i) **Day-Ahead and Real-Time Congestion Revenue** – For each settlement interval, the ISO will determine the total revenues associated with transmission congestion on the New England Transmission System. To accomplish this, the ISO will perform calculations to determine the following. The Day-Ahead Congestion Revenue shall equal the sum of all Market Participants' Day-Ahead Energy Market Congestion Charge/Credits. The Real-Time Congestion Revenue shall equal the sum of all Market Participants' Real-Time Energy Market Deviation Congestion Charge/Credits.

(j) **Day-Ahead Loss Revenue** – For each settlement interval, the ISO will determine the excess or deficiency in loss revenue associated with the Day-Ahead Energy Market. The Day-Ahead Loss Revenue shall be equal to the sum of all Market Participants' Day-Ahead Energy Market Energy Charge/Credits and Day-Ahead Energy Market Loss Charge/Credits.

(k) **Day-Ahead Loss Charges or Credits** – For each settlement interval for each Market Participant, the ISO shall calculate a Day-Ahead payment or charge associated with the excess or deficiency in loss revenue (Section III.3.2.1(j)). The Day-Ahead Loss Charges or Credits shall be equal to the Day-Ahead Loss Revenue multiplied by the Market Participant's pro rata share of the sum of all Market Participants' Marginal Loss Revenue Load Obligations.

(l) **Real-Time Loss Revenue** – For each settlement interval, the ISO will determine the excess or deficiency in loss revenue associated with the Real-Time Energy Market. The Real-Time Loss Revenue shall be equal to the sum of all Market Participants' Real-Time Energy Market Deviation Energy Charge/Credit and Real-Time Energy Market Deviation Loss Charge/Credit plus Non-Market Participant Transmission Customer loss costs. The ISO will then adjust Real-Time Loss Revenue to account for

Inadvertent Energy Revenue, as calculated under Section III.3.2.1(o) and Emergency transactions as described under Section III.4.3(a).

(m) **Real-Time Loss Revenue Charges or Credits** – For each hour for each Market Participant, the ISO shall calculate a Real-Time payment or charge associated with the excess or deficiency in Real-Time Loss Revenue (Section III.3.2.1(l)). The Real-Time Loss Revenue Charges or Credits shall be equal to the Real-Time Loss Revenue multiplied by the Market Participant's pro rata share of the sum of all Market Participants' Marginal Loss Revenue Load Obligations.

(n) **Non-Market Participant Loss** – Non-Market Participant Transmission Customer loss costs shall be assessed for transmission use scheduled in the Real-Time Energy Market, calculated as the amount to be delivered in each settlement interval multiplied by the difference between the Loss Component of the Real-Time Price at the delivery point or New England Control Area boundary delivery interface and the Loss Component of the Real-Time Price at the source point or New England Control Area boundary source interface.

(o) **Inadvertent Energy Revenue** – For each External Node, for each settlement interval the ISO will calculate an excess or deficiency in Inadvertent Energy Revenue by multiplying the Inadvertent Interchange at the External Node by the associated Real-Time Locational Marginal Price. For each settlement interval, the total Inadvertent Energy Revenue for a settlement interval shall equal the sum of the Inadvertent Energy Revenue values for each External Node for that interval.

(p) **Inadvertent Energy Revenue Charges or Credits** – For each hour for each Market Participant, the ISO shall calculate a Real-Time payment or charge associated with the excess or deficiency in Inadvertent Energy Revenue (Section III.3.2.1(o)). The Inadvertent Energy Revenue Charges or Credits shall be equal to the Inadvertent Energy Revenue multiplied by the Market Participant's pro rata share of the sum of all Market Participants' Real-Time Load Obligations, Real-Time Generation Obligations, and Real-Time Demand Reduction Obligations over all Locations, measured as absolute values, excluding contributions to Real-Time Load Obligations and Real-Time Generation Obligations from Coordinated External Transactions.

(q)(1) **Day-Ahead Energy Market Ancillary Services Credit** – Commencing on June 1, 2024, each Market Participant with a Day-Ahead Ancillary Services obligation shall receive a credit as follows:

(i) **Day-Ahead Ten-Minute Spinning Reserve credit** – Each MWh of Day-Ahead Ten-Minute Spinning Reserve Obligation shall be credited the clearing price for Day-Ahead Ten-Minute Spinning Reserve calculated in accordance with Section III.2.6.2(a)(v).

(ii) **Day-Ahead Ten-Minute Non-Spinning Reserve credit** – Each MWh of Day-Ahead Ten-Minute Non-Spinning Reserve Obligation shall be credited the clearing price for Day-Ahead Ten-Minute Non-Spinning Reserve calculated in accordance with Section III.2.6.2(a)(iv).

(iii) **Day-Ahead Thirty-Minute Operating Reserve credit** – Each MWh of Day-Ahead Thirty-Minute Operating Reserve Obligation shall be credited the clearing price for Day-Ahead Thirty-Minute Operating Reserve calculated in accordance with Section III.2.6.2(a)(iii).

(iv) **Day-Ahead Ninety-Minute Reserve credit** – Each MWh of Day-Ahead Ninety-Minute Reserve Obligation shall be credited the clearing price for Day-Ahead Ninety-Minute Reserve calculated in accordance with Section III.2.6.2(a)(ii).

(v) **Day-Ahead Four-Hour Reserve credit** – Each MWh of Day-Ahead Four-Hour Reserve Obligation shall be credited the clearing price for Day-Ahead Four-Hour Reserve calculated in accordance with Section III.2.6.2(a)(i).

(vi) **Day-Ahead Energy Imbalance Reserve credit** – Each MWh of Day-Ahead Energy Imbalance Reserve Obligation shall be credited the clearing price for Day-Ahead Energy Imbalance Reserve calculated in accordance with Section III.2.6.2(a)(vi).

(q)(2) **Day-Ahead Energy Market Ancillary Services Close-Out Charge** – Commencing on June 1, 2024, each Market Participant with a Day-Ahead Ancillary Service obligation shall receive a charge as follows:

(i) **Day-Ahead Generation Contingency Reserve and Day-Ahead Replacement Energy Reserve –** Each MWh of Day-Ahead Ten-Minute Spinning Reserve Obligation, Day-Ahead Ten-Minute Non-Spinning Reserve Obligation, Day-Ahead Thirty-Minute Operating Reserve Obligation, Day-Ahead Ninety-Minute Reserve Obligation, and Day-Ahead Four-Hour Reserve Obligation shall be charged the close-out charge rate, which shall be the greater of (a) the hourly Real-Time Hub Price less the Energy Call Option Strike Price for the hour, and (b) zero.

(ii) **Day-Ahead Energy Imbalance Reserve –** Each MWh of Day-Ahead Energy Imbalance Reserve Obligation shall be charged the close out charge rate determined in accordance with subsection (q)(2)(i).

(q)(3) **Allocation of Net Day-Ahead Generation Contingency Reserve and Day-Ahead Replacement Energy Reserve Credits/Charges** – Commencing on June 1, 2024:

(i) The sum total credits calculated in accordance with Sections III.3.2.1(q)(1)(i)-(v) for Day-Ahead Generation Contingency Reserve and Day-Ahead Replacement Energy Reserve shall be charged on an hourly basis to Market Participants based on their pro rata share of the sum of all Market Participants' Real-Time Load Obligation, excluding Real-Time Load Obligation incurred by Storage DARDs;

(ii) The sum total close-out charges calculated in accordance with Section III.3.2.1(q)(2)(i) for Day-Ahead Generation Contingency Reserve and Day-Ahead Replacement Energy Reserve shall be credited on an hourly basis to Market Participants based on their pro rata share of the sum of all Market Participants' Real-Time Load Obligation, excluding Real-Time Load Obligation incurred by Storage DARDs.

(q)(4) **Allocation of Net Day-Ahead Energy Imbalance Reserve Credits/Charge** – Commencing on June 1, 2024:

(i) For purposes of this subsection (q)(4), the ISO will calculate a load deviation amount for each Market Participant. The load deviation shall be equal to the greater of (a) the MWh amount of the Market Participant's Real-Time Load Obligation (excluding Real-Time Load Obligation incurred by Storage DARDs) minus its Day-Ahead Load Obligation (excluding Day-Ahead Load Obligation incurred by Storage DARDs), or (b) zero.

(ii) The sum of credits calculated in accordance with Section III.3.2.1(q)(1)(vi) for Day-Ahead Energy Imbalance Reserve, if non-zero, shall be charged to Market Participants on an hourly basis as follows:

If the sum of (a) all Market Participants' load deviations and (b) accepted Increment Offers is

equal to or less than the total Day-Ahead Energy Imbalance Reserve Obligation amount, each Market Participant shall be charged: (1) the Day-Ahead Energy Imbalance Reserve clearing price, calculated in accordance with Section III.2.6.2(a)(vi) of this Market Rule 1, multiplied by the Market Participant's accepted Increment Offer amount, and (2) the Day-Ahead Energy Imbalance Reserve clearing price multiplied by the Market Participant's load deviation amount. The balance of any remaining credits for Day-Ahead Energy Imbalance Reserve Obligation shall be charged to Market Participants based on their pro rata share of the sum of all Market Participants' Real-Time Load Obligation, excluding Real-Time Load Obligation incurred by Storage DARDs.

If the sum of (a) all Market Participants' load deviations and (b) accepted Increment Offers is greater than the total Day-Ahead Energy Imbalance Reserve Obligation amount, and if the sum of all Market Participants' load deviations is greater than zero, each Market Participant shall be charged the Day-Ahead Energy Imbalance Reserve clearing price, calculated in accordance with Section III.2.6.2(a)(vi) of this Market Rule 1, multiplied by the Market Participant's accepted Increment Offer amount. The balance of any remaining credits for Day-Ahead Energy Imbalance Reserve Obligation shall be charged to Market Participants based on their pro rata share of the sum of all Market Participants' load deviations.

If the sum of all Market Participants' accepted Increment Offers is greater than the total Day-Ahead Energy Imbalance Reserve Obligation amount, and if the sum of all Market Participants' load deviations is zero, each MWh of a Market Participant's accepted Increment Offer shall be charged the Day-Ahead Energy Imbalance Reserve clearing price, calculated in accordance with Section III.2.6.2(a)(vi) of this Market Rule 1, multiplied by the total Day-Ahead Energy Imbalance Reserve Obligation amount and divided by the sum of all Market Participants' accepted Increment Offer amounts.

(iii) The sum of close-out charges calculated in accordance with Section III.3.2.1(q)(2)(ii) for Day-Ahead Energy Imbalance Reserve, if non-zero, shall be allocated to Market Participants on an hourly basis as follows:

If the sum of (a) all Market Participants' load deviations and (b) accepted Increment Offers is equal to or less than the total Day-Ahead Energy Imbalance Reserve Obligation amount, each Market Participant shall be credited an amount equal to: (1) close-out charge rate determined in

accordance with Section III.3.2.1(q)(2)(ii) for the settlement interval multiplied by the Market Participant's accepted Increment Offer amount, and (2) the close-out charge rate determined in accordance with Section III.3.2.1(q)(2)(ii) for the settlement interval, multiplied by their load deviation amount. The balance of any remaining charges for Day-Ahead Energy Imbalance Reserve Obligations shall be credited to Market Participants based on their pro rata share of the sum of all Market Participants' Real-Time Load Obligation, excluding Real-Time Load Obligation incurred by Storage DARDs.

If the sum of (a) all Market Participants' load deviations and (b) accepted Increment Offers is greater than the total Day-Ahead Energy Imbalance Reserve Obligation amount, and if the sum of all Market Participants' load deviations is greater than zero, each Market Participant shall be credited an amount equal to the close-out charge rate determined in accordance with Section III.3.2.1(q)(2)(ii) for the settlement interval multiplied by the Market Participant's accepted Increment Offer amount. The balance of any remaining charges for Day-Ahead Energy Imbalance Reserve Obligation shall be credited to Market Participants based on their pro rata share of the sum of all Market Participants' load deviations.

If the sum of all Market Participants' accepted increment Offers is greater than the total Day-Ahead Energy Imbalance Reserve Obligation amount, and if the sum of all Market Participants' load deviations is zero, each MWh of a Market Participant's accepted Increment Offer shall be credited an amount equal to the close-out charge rate determined in accordance with Section III.3.2.1(q)(2)(ii) for the settlement interval multiplied by the Market Participant's accepted Increment Offer amount, multiplied by the total Day-Ahead Energy Imbalance Reserve Obligation amount and divided by the sum of all Market Participants' accepted Increment Offer amounts.

(q)(5) **Forecast Energy Requirement Credit -** Commencing on June 1, 2024, Market Participants with Generator Assets, Demand Response Resources, and External Transactions for the supply of energy scheduled in the Day-Ahead Energy Market shall be credited the Forecast Energy Requirement Price, calculated in accordance with Section III.2.6.2(a)(vii), for each MWh of the resource's Day-Ahead energy obligation.

(q)(6) **Forecast Energy Requirement Charge** – The total amount credited in accordance with Section III.3.2.1(q)(5) shall be charged on an hourly basis to Market Participants as follows:

(i) Market Participants shall be charged the Forecast Energy Requirement Price, calculated in accordance with Section III.2.6.2(a)(vii), for each MWh of the Market Participant's Day-Ahead External Transaction sales.

(ii) The balance of any remaining credits shall be charged to Market Participants based on their pro rata share of the sum of all Market Participants' Real-Time Load Obligations, excluding Real-Time Load Obligations incurred by Real-Time External Transaction sales and Storage DARDs.

III.3.2.1.1 Metered Quantity For Settlement.

For purposes of determining the Metered Quantity For Settlement, the five-minute telemetry value for a five-minute interval is the integrated value of telemetered data sampled over the five-minute period. For settlement calculations that require hourly revenue quality meter value from Resources that submit five-minute revenue quality meter data, the hourly revenue quality meter value is the average of five-minute revenue quality meter values for the hour. The Metered Quantity For Settlement is calculated as follows:

(a) For external interfaces, the Metered Quantity For Settlement is the scheduled value adjusted for any curtailment, except that for Inadvertent Interchange, the Metered Quantity For Settlement is the difference between the actual and scheduled values, where the actual value is

(i) calculated as the five-minute telemetry value plus the difference between the hourly revenue quality meter value and the hourly average telemetry value, or

(ii) the five-minute revenue quality meter value, if five-minute revenue quality meter data are available.

(b) For Resources submitting five-minute revenue quality meter data (other than Demand Response Resources), the Metered Quantity For Settlement is the five-minute revenue quality meter value.

(c) For Resources with telemetry submitting hourly revenue quality meter data, the Metered Quantity For Settlement is calculated as follows:

(i) In the event that in an hour, the difference between the average of the five-minute telemetry values for the hour and the revenue quality meter value for the hour is greater than 20 percent of the hourly revenue quality meter value and greater than 10 MW then the Metered Quantity For Settlement is a flat profile of the revenue quality meter value equal to the hourly revenue quality meter value equally apportioned over the five-minute intervals in the hour. (For a Continuous Storage Facility, the difference between the

average of the five-minute telemetry values and the revenue quality meter value will be determined using the net of the values submitted by its component Generator Asset and DARD.)

(ii) Otherwise, the Metered Quantity For Settlement is the telemetry profile of the revenue quality meter value equal to the five-minute telemetry value adjusted by a scale factor.

(d) For a Demand Response Resource, the Metered Quantity For Settlement equals the sum of the demand reductions of each of its constituent Demand Response Assets produced in response to a non-zero Dispatch Instruction, with the demand reduction for each such asset calculated pursuant to Section III.8.4.

(e) For Resources without telemetry submitting hourly revenue quality meter data, the Metered Quantity For Settlement is the hourly revenue quality meter value equally apportioned over the five-minute intervals in the hour.

III.3.2.2 Metering and Communication.

(a) Revenue Quality Metering and Telemetry for Assets other than Demand Response Assets

The megawatt-hour data of each Generator Asset, Tie-Line Asset, and Load Asset must be metered and automatically recorded at no greater than an hourly interval using metering located at the asset's point of interconnection, in accordance with the ISO operating procedures on metering and telemetering. This metered value is used for purposes of establishing the hourly revenue quality metering of the asset.

The instantaneous megawatt data of each Generator Asset (except Settlement Only Resources) and each Asset Related Demand must be automatically recorded and telemetered in accordance with the requirements in the ISO operating procedures on metering and telemetering.

(b) Meter Maintenance and Testing for all Assets

Each Market Participant must adequately maintain metering, recording and telemetering equipment and must periodically test all such equipment in accordance with the ISO operating procedures on metering and telemetering. Equipment failures must be addressed in a timely manner in accordance with the requirements in the ISO operating procedures on maintaining communications and metering equipment.

(c) Additional Metering and Telemetry Requirements for Demand Response Assets

(i) Market Participants must report to the ISO in real time a set of telemetry data for each Demand Response Asset associated with a Demand Response Resource. The telemetry values shall measure the real-time demand of Demand Response Assets as measured at their Retail Delivery Points, and shall be reported to the ISO every five minutes. For a

Demand Response Resource to provide TMSR or TMNSR, Market Participants must in addition report telemetry values at least every one minute. Telemetry values reported by Market Participants to the ISO shall be in MW units and shall be an instantaneous power measurement or an average power value derived from an energy measurement for the time interval from which the energy measurement was taken.

(ii) If one or more generators whose output can be controlled is located behind the Retail Delivery Point of a Demand Response Asset, other than emergency generators that cannot operate electrically synchronized to the New England Transmission System, then the Market Participant must also report to the ISO, before the end of the Correction Limit for the Data Reconciliation Process, a single set of meter data, at an interval of five minutes, representing the combined output of all generators whose output can be controlled.

(iii) If the Market Participant or the ISO finds that the metering or telemetry devices do not meet the accuracy requirements specified in the ISO New England Manuals and Operating Procedures, the Market Participant shall promptly notify the ISO and indicate when it expects to resolve the accuracy problem(s), or shall request that the affected Demand Response Assets be retired. Once such an issue becomes known and until it is resolved, the demand reduction value and Operating Reserve capability of any affected Demand Response Asset shall be excluded from the Demand Response Resource with which it is associated.

(iv) The ISO may review and audit testing and calibration records, audit facility performance (including review of facility equipment), order and witness the testing of metering and telemetry measurement equipment, and witness the demand reduction activities of any facility or generator associated with a Demand Response Asset. Market Participants must make retail billing meter data and any interval meter data from the Host Participant for the facilities associated with a Demand Response Asset available to the ISO upon request.

(d) Overuse of Flat Profiling

In the event a Market Participant’s telemetry is replaced with an hourly flat profile pursuant to Section III.3.2.1.1(c)(i) more than 20% of the online hours in a month and Market Participant’s Resource has been online for over 50 hours in the month, the ISO may consult with the Market Participant for an explanation of the regular use of flat profiling and may request that the Market Participant address any telemetry discrepancies so that flat profiling is not regularly triggered.

Within 10 business days of issuance of such a request, the Market Participant shall provide the ISO with a written plan for remedying the deficiencies, and shall identify in the plan the specific actions to be taken and a reasonable timeline for completing such remediation. The Market Participant shall complete the remediation in accordance with and under the timeline set forth in the written plan.

III.3.2.3 NCPC Credits and Charges.

A Market Participant's NCPC Credits and NCPC Charges are calculated pursuant to Appendix F to Market Rule 1.

III.3.2.4 Transmission Congestion.

Market Participants shall be charged or credited for Congestion Costs as specified in Section III.3.2.1(i) of this Market Rule 1.

III.3.2.5 [Reserved.]

III.3.2.6 Emergency Energy.

(a) For each settlement interval during an hour in which there are Emergency Energy purchases, the ISO calculates an Emergency Energy purchase charge or credit equal to the Emergency Energy purchase price minus the External Node Real-Time LMP for the interval, multiplied by the Emergency Energy quantity for the interval. The charge or credit for each interval in an hour is summed to an hourly value. The ISO allocates the hourly charges or credits to Market Participants based on the following hourly deviations where such deviations are negative: (i) Real-Time Adjusted Load Obligation Deviations during that Operating Day; (ii) generation deviations and demand reduction deviations for those Pool-Scheduled Resources and Continuous Storage Generator Assets that are not following Dispatch Instructions; Self-Scheduled Resources (other than Continuous Storage Generator Assets) with dispatchable capability above their Self-Scheduled amounts not following Dispatch Instructions; and Self-Scheduled Resources (other than Continuous Storage Generator Assets) not following their Day-Ahead Self-Scheduled amounts other than those following Dispatch Instructions; in MWhs during the Operating Day; and (iii) deviations from the Day-Ahead Energy Market for External Transaction purchases in MWhs during the Operating Day except that positive Real-Time Generation Obligation Deviation at External Nodes associated with Emergency Energy purchases are not included in this calculation. Generator Assets and Demand Response Resources shall have a 5% or 5 MWh threshold when determining such deviations. Notwithstanding the foregoing, the allocation of costs or credits attributable to the purchase of Emergency

Energy from other Control Areas shall exclude contributions to deviations from Coordinated External Transactions.

(b) For each settlement interval during an hour in which there are Emergency Energy sales, the ISO calculates Emergency Energy sales revenue, exclusive of revenue from the Real-Time Energy Market, received from other Control Areas to provide the Emergency Energy sales. The revenues for each interval in an hour is summed to an hourly value. Hourly net revenues attributable to the sale of Emergency Energy to other Control Areas shall be credited to Market Participants based on the following deviations where such deviations are negative: (i) Real-Time Adjusted Load Obligation Deviations in MWhs during that Operating Day; (ii) generation deviations and demand reduction deviations for those Pool-Scheduled Resources and Continuous Storage Generator Assets that are following Dispatch Instructions; and Self-Scheduled Generator Assets (other than Continuous Storage Generator Assets) with dispatchable capability above their Self-Scheduled amounts following Dispatch Instructions; in MWhs during the Operating Day; and (iii) deviations from the Day-Ahead Energy Market for External Transaction purchases in MWhs during the Operating Day except that positive Real-Time Generation Obligation Deviation at External Nodes associated with Emergency Energy purchases are not included in this calculation. Generator Assets and Demand Response Resources shall have a 5% or 5 MWh threshold when determining such deviations. Notwithstanding the foregoing, the calculation of the credit for the sale of Emergency Energy to other Control Areas shall exclude contributions to deviations from Coordinated External Transactions.

III.3.2.6A New Brunswick Security Energy.

New Brunswick Security Energy is energy that is purchased from the New Brunswick System Operator by New England to preserve minimum flows on the Orrington-Keswick (396/3001) tie line and Orrington-Lepreau (390/3016) tie line in accordance with the applicable ISO / New Brunswick System Operator transmission operating guide with respect to the determination of minimum transfer limits. New Brunswick Security Energy costs are hourly costs in excess of the LMP at the applicable External Node attributable to purchases of New Brunswick Security Energy by New England. New Brunswick Security Energy costs shall be allocated among Market Participants on the basis of their pro-rata shares of Regional Network Load. Where the LMP at the applicable External Node exceeds the New Brunswick Security Energy costs, such amounts shall be accounted for in accordance with Section III.3.2.1(m).

III.3.2.7 Billing.

The ISO shall prepare a billing statement each billing cycle, in accordance with the ISO New England Billing Policy, for each Market Participant in accordance with the charges and credits specified in Sections III.3.2.1 through III.3.2.6, and showing the net amount to be paid or received by the Market Participant. Billing statements shall provide sufficient detail, as specified in the ISO New England Manuals, ISO New England Administrative Procedures and the ISO New England Billing Policy, to allow verification of the billing amounts and completion of the Market Participant's internal accounting. Billing disputes shall be settled in accordance with procedures specified in the ISO New England Billing Policy.

III.3.3 [Reserved.]

III.3.4 Non-Market Participant Transmission Customers.

III.3.4.1 Transmission Congestion.

Non-Market Participant Transmission Customers shall be charged or credited for Congestion Costs as specified in Section III.1 of this Market Rule 1.

III.3.4.2 Transmission Losses.

Non-Market Participant Transmission Customers shall be charged or credited for transmission losses in an amount equal to the product of (i) the Transmission Customer's MWhs of deliveries in the Real-Time Energy Market, multiplied by (ii) the difference between the Loss Components of the Real-Time Locational Marginal Prices at the point-of-receipt and the point-of-delivery Locations.

III.3.4.3 Billing.

The ISO shall prepare a billing statement each billing cycle, in accordance with the ISO New England Billing Policy, for each Non-Market Participant Transmission Customer in accordance with the charges and credits specified in Sections III.3.4.1 through III.3.4.2 of this Market Rule 1, and showing the net amount to be paid or received by the Non-Market Participant Transmission Customer. Billing statements shall provide sufficient detail, as specified in the ISO New England Manuals, the ISO New England Administrative Procedures and the ISO New England Billing Policy, to allow verification of the billing amounts and completion of the Non-Market Participant Transmission Customer's internal accounting. Billing disputes shall be settled in accordance with procedures specified in the ISO New England Billing Policy.

III.3.5 [Reserved.]

III.3.6 Data Reconciliation.

III.3.6.1 Data Correction Billing.

The ISO will reconcile Market Participant data errors and corrections after the Correction Limit for such data has passed. The Correction Limit for meter data and for ISO errors in the processing of meter and other Market Participant data is 101 days from the last Operating Day of the month to which the data applied. Notification of Meter Data Errors applicable to Assigned Meter Reader or Host Participant Assigned Meter Reader supplied meter data must be submitted to the ISO by the Meter Data Error RBA Submission Limit.

III.3.6.2 Eligible Data.

The ISO will accept revised hourly asset meter readings from Assigned Meter Readers and Host Participant Assigned Meter Readers, daily Coincident Peak Contribution values from Assigned Meter Readers, and new or revised internal bilateral transactions from Market Participants. No other revised data will be accepted for use in settlement recalculations. The ISO will correct data handling errors associated with other Market Participant supplied data to the extent that such data did not impact unit commitment or the Real-Time dispatch. Data handling errors that impacted unit commitment or the Real-Time dispatch will not be corrected.

III.3.6.3 Data Revisions.

The ISO will accept revisions to asset specific meter data, daily Coincident Peak Contribution values, and internal bilateral transactions prior to the Correction Limit. No revisions to other Market Participant data will be accepted after the deadlines specified in the ISO New England Manuals for submittal of that data have passed, except as provided in Section III.3.8 of Market Rule 1. If the ISO discovers a data error or if a Market Participant discovers and notifies the ISO of a data error prior to the Correction Limit, revised hourly data will be used to recalculate all markets and charges as appropriate, including but not limited to energy, NCPC, Regulation, Operating Reserves, Auction Revenue Rights allocations, Forward Capacity Market, cost-of-service agreements, and the ISO Tariff. No settlement recalculations or other adjustments may be made if the Correction Limit for the Operating Day to which the error applied has passed or if the correction does not qualify for treatment as a Meter Data Error correction pursuant to Section III.3.8 of Market Rule 1.

III.3.6.4 Meter Corrections Between Control Areas.

For revisions to meter data associated with assets that connect the New England Control Area to other Control Areas, the ISO will, in addition to performing settlement recalculations, adjust the actual interchange between the New England Control Area and the other Control Area to maintain an accurate record of inadvertent energy flow.

III.3.6.5 Meter Correction Data.

(a) Revised meter data and daily Coincident Peak Contribution values shall be submitted to the ISO as soon as it is available and not later than the Correction Limit, and must be submitted in accordance with the criteria specified in Section III.3.7 of Market Rule 1. Specific data submittal deadlines are detailed in the ISO New England Manuals.

(b) Errors on the part of the ISO in the administration of Market Participant supplied data shall be brought to the attention of the ISO as soon as possible and not later than the Correction Limit.

III.3.7 Eligibility for Billing Adjustments.

(a) Errors in Market Participant's statements resulting from errors in settlement software, errors in data entry by ISO personnel, and settlement production problems, that do not affect the day-ahead schedule or real-time system dispatch, will be corrected as promptly as practicable. If errors are identified prior to the issuance of final statements, the market will be resettled based on the corrected information.

(b) Calculations made by scheduling or dispatch software, operational decisions involving ISO discretion which affect scheduling or real-time operation, and the ISO's execution of mandatory dispatch directions, such as self-schedules or external contract conditions, are not subject to retroactive correction and resettlement. The ISO will settle and bill the Day-Ahead Energy Market as actually scheduled and the Real-Time Energy Market as actually dispatched. Any post-settlement issues raised concerning operating decisions related to these markets will be corrected through revision of operations procedures and guidelines on a prospective basis.

(c) While errors in reporting hourly metered data may be corrected (pursuant to Section III.3.8), Market Participants have the responsibility to ensure the correctness of all data they submit to the market settlement system.

(d) Disputes between Market Participants regarding settlement of internal bilateral transactions shall not be subject to adjustment by the ISO, but shall be resolved directly by the Market Participants unless they involve an error by the ISO that is subject to resolution under Section III.3.7(a).

(e) Billing disputes between Market Participants and the ISO or Non-Market Participants and the ISO shall be settled in accordance with procedures specified in the ISO New England Billing Policy.

(f) Criteria for Meter Data Errors to be eligible for a Requested Billing Adjustment. In order to be eligible to submit a Requested Billing Adjustment due to a Meter Data Error on an Invoice issued by the ISO after the completion of the Data Reconciliation Process, a Market Participant must satisfy one of the following two conditions: (1) the Meter Data Error at issue was identified by the asset owner, Assigned Meter Reader or the Host Participant Assigned Meter Reader and communicated to the Host Participant Assigned Meter Reader no later than thirty-six (36) days prior to the Correction Limit for Directly Metered Assets and no later than two (2) days prior to the Correction Limit for Profiled Load Assets and could not be resolved prior to those deadlines; or (2) the Meter Data Error at issue was identified by the asset owner, Assigned Meter Reader or Host Participant Assigned Meter Reader and reported to the ISO by the Meter Data Error RBA Submission Limit, and such Meter Data Error represents an error that is equal to or greater than the 1,000 MWh per Asset over a calendar month. If the Meter Data Error affects more than one metering domain, the ISO, and affected Host Participant Assigned Meter Readers and affected Assigned Meter Readers of affected metering domains, must be notified.

III.3.8 Correction of Meter Data Errors

(a) Any Market Participant, Assigned Meter Reader or Host Participant Assigned Meter Reader may submit notification of a Meter Data Error in accordance with the procedures provided in this Section III.3.8, provided that the notification is submitted no later than the Meter Data Error RBA Submission Limit and that the notice must be submitted using the RBA form for Meter Data Errors posted on the ISO's website. Errors in telemetry values used in calculating Metered Quantity For Settlement are not eligible for correction under this Section III.3.8.

(b) Within three Business Days of the receipt by the ISO's Chief Financial Officer of an RBA form for a Meter Data Error, the ISO shall prepare and submit to all Covered Entities and to the Chair of the NEPOOL Budget and Finance Subcommittee a notice of the Meter Data Error correction ("Notice of Meter Data Error Correction"), including, subject to the provisions of the ISO New England Information Policy, the specific details of the correction and the identity of the affected metering domains and the

affected Host Participant Assigned Meter Readers. The “Notice of Meter Data Error Correction” shall identify a specific representative of the ISO to whom all communications regarding the matter are to be sent.

(c) In order for a Meter Data Error on an Invoice issued by the ISO after the completion of the Data Reconciliation Process to be eligible for correction, the Meter Data Error must satisfy one of the following conditions: (1) the Meter Data Error at issue was identified by the asset owner, Assigned Meter Reader or the Host Participant Assigned Meter Reader and communicated to the Host Participant Assigned Meter Reader no later than 36 days prior to the Correction Limit for Directly Metered Assets and no later than two days prior to the Correction Limit for Profiled Load Assets and could not be resolved prior to those deadlines; (2) the Meter Data Error at issue was identified by the asset owner, Assigned Meter Reader or Host Participant Assigned Meter Reader, and such Meter Data Error represents an error that is equal to or greater than the 1,000 MWh per asset over a calendar month; and (3) if the Meter Data Error involves only Coincident Peak Contribution values, the average of the daily Meter Data Errors involving Coincident Peak Contribution values for the affected calendar month must be greater than or equal to 5 MW for an affected asset. If the Meter Data Error affects more than one metering domain, the ISO, and affected Host Participant Assigned Meter Readers and affected Assigned Meter Readers of affected metering domains, must be notified.

(d) For a Meter Data Error, the Host Participant Assigned Meter Reader must submit to the ISO corrected meter data for Directly Metered Assets prior to the 46th calendar day after the Meter Data Error RBA Submission Limit. Corrected metered data for Profiled Load Assets and Coincident Peak Contribution values, must be submitted to the ISO by the Host Participant Assigned Meter Reader prior to the 87th calendar day after the Meter Data Error RBA Submission Limit. Corrected internal bilateral transactions data must be submitted to the ISO by a Market Participant prior to the 91st calendar day after the Meter Data Error RBA Submission Limit.

Any corrected data received after the specified deadlines is not eligible for use in the settlement process.

The Host Participant Assigned Meter Reader or Market Participant, as applicable, must confirm as part of its submission of corrected data that the eligibility criteria described in Section III.3.8(c) of Market Rule 1 have been satisfied.

To the extent that the correction of a Meter Data Error is for a Directly Metered Asset that affects multiple metering domains, all affected Host Participant Assigned Meter Readers or Assigned Meter Readers must notify the ISO prior to the 46th calendar day after the Meter Data Error RBA Submission Limit that the corrected Directly Metered Asset data is acceptable to them in order for the ISO to use the corrected data in the final settlement calculations. The Host Participant Assigned Meter Reader for the Directly Metered Asset is responsible for initiating an e-mail to every affected Host Participant Assigned Meter Reader or Assigned Meter Reader in order to obtain such acceptance and shall coordinate delivery of such acceptance to the ISO. The Host Participant Assigned Meter Reader for the Directly Metered Asset is also responsible for submitting all corrected and agreed upon Directly Metered Asset data to the ISO prior to the 46th calendar day after the Meter Data Error RBA Submission Limit.

(e) After the submission of corrected meter and internal bilateral transactions data, the ISO will have a minimum of 30 calendar days to administer the final settlement based on that data. Revised data will be used to recalculate all charges and credits, except that revised data will not be used to recalculate the PER adjustment, including the Hourly PER and Monthly PER values. Revised data will also not be used to recalculate Demand Resource Seasonal Peak Hours. The results of the final settlement will then be included in the next Invoice containing Non-Hourly Charges and the ISO will provide to the Chair of the NEPOOL Budget and Finance Subcommittee written notification that the final settlement has been administered.

III.4 Rate Table

III.4.1 Offered Price Rates.

Day-Ahead energy, Day-Ahead Ancillary Services as of June 1, 2024, Real-Time energy, Regulation, Real-Time Operating Reserve, Forward Reserve, NCPC, Congestion Cost and transmission loss costs are based on offers and bids submitted to the ISO as specified in this Market Rule 1.

III.4.2 [Reserved.]

III.4.3 Emergency Energy Transaction.

The pricing for Emergency Energy and New Brunswick Security Energy purchases and sales will be determined in accordance with:

(a) an applicable agreement with an adjacent Control Area for Emergency and/or New Brunswick Security Energy purchases and sales, or

(b) arrangements made by the ISO with Market Participants, in accordance with procedures defined in the ISO New England Manuals, to purchase Emergency Energy offered by such Market Participant from External Transactions that are not associated with Import Capacity Resources. The ISO shall select offers to sell Emergency Energy made by Market Participants to the ISO on a least cost basis and the selected Market Participants shall receive payment for energy delivered at the higher of their offer price or the Real-Time Price at the applicable External Node. Such Emergency Energy purchases from Market Participants shall not be eligible to set Real-Time Prices.

III.13.2. Annual Forward Capacity Auction.

III.13.2.1. Timing of Annual Forward Capacity Auctions.

Each Forward Capacity Auction will be conducted beginning on the first Monday in the February that is approximately three years and four months before the beginning of the associated Capacity Commitment Period (unless, no later than the immediately preceding December 1, an alternative date is announced by the ISO), or, where exigent circumstances prevent the start of the Forward Capacity Auction at that time, as soon as possible thereafter.

III.13.2.2. Amount of Capacity Cleared in Each Forward Capacity Auction.

The total amount of capacity cleared in each Forward Capacity Auction shall be determined using the System-Wide Capacity Demand Curve and the Capacity Zone Demand Curves for the modeled Capacity Zones pursuant to Section III.13.2.3.3.

III.13.2.2.1. System-Wide Capacity Demand Curve.

The MRI Transition Period is the period from the Forward Capacity Auction for the Capacity Commitment Period beginning June 1, 2020 through the earlier of:

(i) the Forward Capacity Auction for which the amount of the Installed Capacity Requirement (net of HQICCs) that is filed by the ISO with the Commission pursuant to Section III.12.3 for the upcoming Forward Capacity Auction is greater than or equal to the sum of: 34,151 MW, and: (a) 722 MW (for the Forward Capacity Auction for the Capacity Commitment Period beginning June 1, 2020); (b) 375 MW (for the Forward Capacity Auction for the Capacity Commitment Period beginning June 1, 2021), or; (c) 150 MW (for the Forward Capacity Auction for the Capacity Commitment Period beginning June 1, 2022);

(ii) the Forward Capacity Auction for which the product of the system-wide Marginal Reliability Impact value, calculated pursuant to Section III.12.1.1, and the scaling factor specified in Section III.13.2.2.4, specifies a quantity at $7.03/kW-month in excess of the MW value determined under the applicable subsection (2)(b), (2)(c), or (2)(d), below, or;

(iii) the Forward Capacity Auction for the Capacity Commitment Period beginning June 1, 2022.

During the MRI Transition Period, the System-Wide Capacity Demand Curve shall consist of the following three segments:

(1) at prices above \$7.03/kW-month and below the Forward Capacity Auction Starting Price, the System-Wide Capacity Demand Curve shall specify a price for system capacity quantities based on the product of the system-wide Marginal Reliability Impact value, calculated pursuant to Section III.12.1.1, and the scaling factor specified in Section III.13.2.2.4;

(2) at prices below \$7.03/kW-month, the System-Wide Capacity Demand Curve shall be linear between \$7.03/kW-month and \$0.00/kW-month and determined by the following quantities:

(a) At the price of \$0.00/kW-month, the quantity specified by the System-Wide Capacity Demand Curve shall be 1616 MW plus the MW value determined under the applicable provision in (b), (c), or (d) of this subsection.

(b) for the Forward Capacity Auction for the Capacity Commitment Period beginning June 1, 2020, at \$7.03/kW-month, the quantity shall be the lesser of:

1. 35,437 MW; and
2. 722 MW plus the quantity at which the product of the system-wide Marginal Reliability Impact value and the scaling factor yield a price of \$7.03/kW-month;

(c) for the Forward Capacity Auction for the Capacity Commitment Period beginning June 1, 2021, at \$7.03/kW-month, the quantity shall be the lesser of:

1. 35,090 MW; and
2. 375 MW plus the quantity at which the product of the system-wide Marginal Reliability Impact value and the scaling factor yield a price of \$7.03/kW-month;

(d) for the Forward Capacity Auction for the Capacity Commitment Period beginning June 1, 2022, at \$7.03/kW-month, the quantity shall be the lesser of:

1. 34,865 MW; and
2. 150 MW plus the quantity at which the product of the system-wide Marginal Reliability Impact value and the scaling factor yield a price of \$7.03/kW-month

(3) a price of $7.03/kW-month for all quantities between those curves segments.

In addition to the foregoing, the System-Wide Capacity Demand Curve shall not specify a price in excess of the Forward Capacity Auction Starting Price.

Following the MRI Transition Period, the System-Wide Capacity Demand Curve shall specify a price for system capacity quantities based on the product of the system-wide Marginal Reliability Impact value, calculated pursuant to Section III.12.1.1, and the scaling factor specified in Section III.13.2.2.4. For any system capacity quantity greater than 110% of the Installed Capacity Requirement (net of HQICCs), the System-Wide Capacity Demand Curve shall specify a price of zero. The System-Wide Capacity Demand Curve shall not specify a price in excess of the Forward Capacity Auction Starting Price.

III.13.2.2.2. Import-Constrained Capacity Zone Demand Curves.

For each import-constrained Capacity Zone, the Capacity Zone Demand Curve shall specify a price for all Capacity Zone quantities based on the product of the import-constrained Capacity Zone's Marginal Reliability Impact value, calculated pursuant to Section III.12.2.1.3, and the scaling factor specified in Section III.13.2.2.4. The prices specified by an import-constrained Capacity Zone Demand Curve shall be non-negative. At all quantities greater than the truncation point, which is the amount of capacity for which the Capacity Zone Demand Curve specifies a price of $0.01/kW-month, the Capacity Zone Demand Curve shall specify a price of zero. The Capacity Zone Demand Curve shall not specify a price in excess of the Forward Capacity Auction Starting Price.

III.13.2.2.3. Export-Constrained Capacity Zone Demand Curves.

For each export-constrained Capacity Zone, the Capacity Zone Demand Curve shall specify a price for all Capacity Zone quantities based on the product of the export-constrained Capacity Zone's Marginal Reliability Impact value, calculated pursuant to Section III.12.2.2.1, and the scaling factor specified in Section III.13.2.2.4. The prices specified by an export-constrained Capacity Zone Demand Curve shall be non-positive. At all quantities less than the truncation point, which is the amount of capacity for which the Capacity Zone Demand Curve specifies a price of negative $0.01/kW-month, the Capacity Zone Demand Curve shall specify a price of zero.

III.13.2.2.4. Capacity Demand Curve Scaling Factor.

The demand curve scaling factor shall be set at the value such that, at the quantity specified by the System-Wide Capacity Demand Curve at a price of Net CONE, the Loss of Load Expectation is 0.1 days per year.

III.13.2.3. Conduct of the Forward Capacity Auction.

The Forward Capacity Auction shall include a descending clock auction, which will determine, subject to the provisions of Section III.13.2.7, the Capacity Clearing Price for each Capacity Zone modeled in that Forward Capacity Auction pursuant to Section III.12.4, and the Capacity Clearing Price for certain offers from New Import Capacity Resources and Existing Import Capacity Resources pursuant to Section III.13.2.3.3(d). The Forward Capacity Auction shall determine the outcome of all offers and bids accepted during the qualification process and submitted during the auction. The descending clock auction shall be conducted as a series of rounds, which shall continue (for up to five consecutive Business Days, with up to eight rounds per day, absent extraordinary circumstances) until the Forward Capacity Auction is concluded for all modeled Capacity Zones in accordance with the provisions of Section III.13.2.3.3. Each round of the Forward Capacity Auction shall consist of the following steps, which shall be completed simultaneously for each Capacity Zone included in the round:

III.13.2.3.1. Step 1: Announcement of Start-of-Round Price and End-of-Round Price.

For each round, the auctioneer shall announce a single Start-of-Round Price (the highest price associated with a round of the Forward Capacity Auction) and a single (lower) End-of-Round Price (the lowest price associated with a round of the Forward Capacity Auction). In the first round, the Start-of-Round Price shall equal the Forward Capacity Auction Starting Price for all modeled Capacity Zones. In each round after the first round, the Start-of-Round Price shall equal the End-of-Round Price from the previous round.

III.13.2.3.2. Step 2: Compilation of Offers and Bids.

The auctioneer shall compile all of the offers and bids for that round, as follows:

(a) **Offers from New Generating Capacity Resources, New Import Capacity Resources, and New Demand Capacity Resources.**

(i) The Project Sponsor for any New Generating Capacity Resource, New Import Capacity Resource that is backed by a single new External Resource and that is associated with an investment in transmission that increases New England's import capability, New Import Capacity

Resource that is associated with an Elective Transmission Upgrade, or New Demand Capacity Resource accepted in the qualification process for participation in the Forward Capacity Auction may submit a New Capacity Offer indicating the quantity of capacity that the Project Sponsor would commit to provide from the resource during the Capacity Commitment Period at that round's prices. A New Capacity Offer shall be defined by the submission of one to five prices, each strictly less than the Start-of-Round Price but greater than or equal to the End-of-Round Price, and an associated quantity in the applicable Capacity Zone. Each price shall be expressed in units of dollars per kilowatt-month to an accuracy of at most three digits to the right of the decimal point, and each quantity shall be expressed in units of MWs to an accuracy of at most three digits to the right of the decimal point. A New Capacity Offer shall imply a supply curve indicating quantities offered at all of that round's prices, pursuant to the convention of Section III.13.2.3.2(a)(iii).

(ii) If the Project Sponsor of a New Generating Capacity Resource, New Import Capacity Resource that is backed by a single new External Resource and that is associated with an investment in transmission that increases New England's import capability, New Import Capacity Resource that is associated with an Elective Transmission Upgrade, or New Demand Capacity Resource elects to offer in a Forward Capacity Auction, the Project Sponsor must offer the resource's full FCA Qualified Capacity at the Forward Capacity Auction Starting Price in the first round of the auction. A New Capacity Offer for a resource may in no event be for greater capacity than the resource's full FCA Qualified Capacity at any price. A New Capacity Offer for a resource may not be for less capacity than the resource's Rationing Minimum Limit at any price, except where the New Capacity Offer is for a capacity quantity of zero.

(iii) Let the Start-of-Round Price and End-of-Round Price for a given round be P_S and P_E, respectively. Let the m prices ($1 \leq m \leq 5$) submitted by a Project Sponsor for a modeled Capacity Zone be $p_1, p_2, \ldots, p_m$, where $P_S > p_1 > p_2 > \ldots > p_m \geq P_E$, and let the associated quantities submitted for a New Capacity Resource be $q_1, q_2, \ldots, q_m$. Then the Project Sponsor's supply curve, for all prices strictly less than P_S but greater than or equal to P_E, shall be taken to be:

$$S(p)=\begin{cases} q_0, & \text{if } p > p_1, \\ q_1, & \text{if } p_2 < p \le p_1, \\ q_2, & \text{if } p_3 < p \le p_2, \\ \cdots & \cdots \quad , \\ q_m, & \text{if } p \le p_m. \end{cases}$$

where, in the first round, q_0 is the resource's full FCA Qualified Capacity and, in subsequent rounds, q_0 is the resource's quantity offered at the lowest price of the previous round.

(iv) Except for Renewable Technology Resources and except as provided in Section III.13.2.3.2(a)(v), a New Capacity Resource may not include any capacity in a New Capacity Offer during the Forward Capacity Auction at any price below the resource's New Resource Offer Floor Price. The amount of capacity included in each New Capacity Offer at each price shall be included in the aggregate supply curves at that price as described in Section III.13.2.3.3.

(v) Capacity associated with a New Import Capacity Resource (other than a New Import Capacity Resource that is backed by a single new External Resource and that is associated with an investment in transmission that increases New England's import capability or a New Import Capacity Resource that is associated with an Elective Transmission Upgrade) shall be automatically included in the aggregate supply curves as described in Section III.13.2.3.3 at prices at or above the resource's offer prices (as they may be modified pursuant to Section III.A.21.2) and shall be automatically removed from the aggregate supply curves at prices below the resource's offer prices (as they may be modified pursuant to Section III.A.21.2), except under the following circumstances:

In any round of the Forward Capacity Auction in which prices are below the Dynamic De-List Bid Threshold, the Project Sponsor for a New Import Capacity Resource (other than a New Import Capacity Resource that is backed by a single new External Resource and that is associated with an investment in transmission that increases New England's import capability or a New Import Capacity Resource that is associated with an Elective Transmission Upgrade) with offer prices (as they may be modified pursuant to Section III.A.21.2) that are less than the Dynamic Delist Bid Threshold may submit a New Capacity Offer indicating the quantity of capacity that the Project Sponsor would commit to provide from the resource during the Capacity Commitment Period at that round's prices. Such an offer shall be defined by the submission of one to five

prices, each less than the Dynamic De-List Bid Threshold (or the Start-of-Round Price, if lower than the Dynamic De-List Bid Threshold) but greater than or equal to the End-of-Round Price, and a single quantity associated with each price. Such an offer shall be expressed in the same form as specified in Section III.13.2.3.2(a)(i) and shall imply a curve indicating quantities at all of that round's relevant prices, pursuant to the convention of Section III.13.2.3.2(a)(iii). The curve may not increase the quantity offered as the price decreases.

(b) **Bids from Existing Capacity Resources**

(i) Static De-List Bids, Permanent De-List Bids, Retirement De-List Bids, and Export Bids from Existing Generating Capacity Resources, Existing Import Capacity Resources, and Existing Demand Capacity Resources, as finalized in the qualification process or as otherwise directed by the Commission shall be automatically bid into the appropriate rounds of the Forward Capacity Auction, such that each such resource's FCA Qualified Capacity will be included in the aggregate supply curves as described in Section III.13.2.3.3 until any Static De-List Bid, Permanent De-List Bid, Retirement D-List Bid, or Export Bid clears in the Forward Capacity Auction, as described in Section III.13.2.5.2, and is removed from the aggregate supply curves. In the case of a Commission-approved Permanent De-List Bid or Commission-approved Retirement De-List Bid at or above the Forward Capacity Auction Starting Price, or where a Permanent De-List Bid or Retirement De-List Bid is subject to an election under Section III.13.1.2.4.1(a), the resource's FCA Qualified Capacity will be reduced by the quantity of the de-list bid (unless the resource was retained for reliability pursuant to Section III.13.1.2.3.1.5.1) and the Permanent De-List Bid or Retirement De-List Bid shall not be included in the Forward Capacity Auction. Permanent De-List Bids and Retirement De-List Bids subject to an election under Section III.13.1.2.4.1(a) or Section III.13.1.2.4.1(b) shall not be included in the Forward Capacity Auction and shall be treated according to Section III.13.2.3.2(b)(ii). In the case of a Static De-List Bid, if the Market Participant revised the bid pursuant to Section III.13.1.2.3.1.1, then the revised bid shall be used in place of the submitted bid; if the Market Participant withdrew the bid pursuant to Section III.13.1.2.3.1.1, then the capacity associated with the withdrawn bid shall be entered into the auction pursuant to Section III.13.2.3.2(c). If the amount of capacity associated with Export Bids for an interface exceeds the transfer limit of that interface (minus any accepted Administrative De-List Bids over that interface), then the set of Export Bids associated with that interface equal to the interface's transfer limit (minus any accepted Administrative De-List Bids over that interface) having the highest bid prices shall be included in the auction as described above;

capacity for which Export Bids are not included in the auction as a result of this provision shall be entered into the auction pursuant to Section III.13.2.3.2(c).

(ii) For Permanent De-List Bids and Retirement De-List Bids, the ISO will enter a Proxy De-List Bid into the appropriate rounds of the Forward Capacity Auction in the following circumstances: (1) if the Lead Market Participant has elected pursuant to Section III.13.1.2.4.1(a) to retire the resource or portion thereof, the resource has not been retained for reliability pursuant to Section III.13.1.2.3.1.5.1, the price specified in the Commission-approved de-list bid is less than the Forward Capacity Auction Starting Price, and the Internal Market Monitor has found a portfolio benefit pursuant to Section III.A.24; or (2) if the Lead Market Participant has elected conditional treatment pursuant to Section III.13.1.2.4.1(b), the resource has not been retained for reliability pursuant to Section III.13.1.2.3.1.5.1, and the price specified in the Commission-approved de-list bid is less than the price specified in the de-list bid submitted by the Lead Market Participant and less than the Forward Capacity Auction Starting Price. The Proxy De-List Bid shall be non-rationable and shall be equal in price and quantity to, and located in the same Capacity Zone as, the Commission-approved Permanent De-List Bid or Commission-approved Retirement De-List Bid, and shall be entered into the appropriate rounds of the Forward Capacity Auction such that the capacity associated with the Proxy De-List Bid will be included in the aggregate supply curves as described in Section III.13.2.3.3 until the Proxy De-List Bid clears in the Forward Capacity Auction, as described in Section III.13.2.5.2, and is removed from the aggregate supply curves. If the Lead Market Participant has elected conditional treatment pursuant to Section III.13.1.2.4.1(b), the resource has not been retained for reliability pursuant to Section III.13.1.2.3.1.5.1, and the Commission-approved Permanent De-List Bid or Commission-approved Retirement De-List Bid is equal to or greater than the de-list bid submitted by the Lead Market Participant, no Proxy De-List Bid shall be used and the Commission-approved de-list bid shall be entered in the Forward Capacity Auction pursuant to Section III.13.2.3.2(b)(i).

(iii) For purposes of this subsection (b), if an Internal Market Monitor-determined price has been established for a Static De-List Bid and the associated resource's capacity is pivotal pursuant to Sections III.A.23.1 and III.A.23.2, then (unless otherwise directed by the Commission) the lower of the Internal Market Monitor-determined price and any revised bid that is submitted pursuant to Section III.13.1.2.3.1.1 will be used in place of the initially submitted bid; provided, however, that if the bid was withdrawn pursuant to Section III.13.1.2.3.1.1, then the capacity associated with the withdrawn bid shall be entered into the auction pursuant to

Section III.13.2.3.2(c). If an Internal Market Monitor-determined price has been established for an Export Bid and the associated resource's capacity is pivotal pursuant to Sections III.A.23.1 and III.A.23.2, then the Internal Market Monitor-determined price (or price directed by the Commission) will be used in place of the submitted bid.

Any Static De-List Bid for ambient air conditions that has not been verified pursuant to Section III.13.1.2.3.2.4 shall not be subject to the provisions of this subsection (b).

(c) **Existing Capacity Resources Without De-List or Export Bids and Self-Supplied FCA Resources**. Each Existing Generating Capacity Resource, Existing Import Capacity Resource, and Existing Demand Capacity Resource without a Static De-List Bid, a Permanent De-List Bid, a Retirement De-List Bid, an Export Bid or an Administrative Export De-List Bid in its Existing Capacity Qualification Package, and each existing Self-Supplied FCA Resource shall be automatically entered into each round of the Forward Capacity Auction at its FCA Qualified Capacity, such that the resource's FCA Qualified Capacity will be included in the aggregate supply curves as described in Section III.13.2.3.3, except where such resource, if permitted, submits an appropriate Dynamic De-List Bid, as described in Section III.13.2.3.2(d). Each new Self-Supplied FCA Resource shall be automatically entered into each round of the Forward Capacity Auction at its designated self-supplied quantity at prices at or above the resource's New Resource Offer Floor Price, such that the resource's designated self-supply quantity will be included in the aggregate supply curves as described in Section III.13.2.3.3.

(d) **Dynamic De-List Bids.** In any round of the Forward Capacity Auction in which prices are below the Dynamic De-List Bid Threshold, any Existing Generating Capacity Resource, Existing Import Capacity Resource, or Existing Demand Capacity Resource (but not any Self-Supplied FCA Resources) may submit a Dynamic De-List Bid at prices below the Dynamic De-List Bid Threshold. Such a bid shall be defined by the submission of one to five prices, each less than the Dynamic De-List Bid Threshold (or the Start-of-Round Price, if lower than the Dynamic De-List Bid Threshold) but greater than or equal to the End-of-Round Price, and a single quantity associated with each price. Such a bid shall be expressed in the same form as specified in Section III.13.2.3.2(a)(i) and shall imply a curve indicating quantities at all of that round's relevant prices, pursuant to the convention of Section III.13.2.3.2(a)(iii). The curve may in no case increase the quantity offered as the price decreases. A dynamic De-List Bid may not offer less capacity than the resource's Rationing Minimum Limit at any price, except where the amount of capacity offered is zero. All Dynamic De-List Bids are subject to a reliability review as described in Section III.13.2.5.2.5, and if not rejected for reliability reasons, shall be included in the round in the same

manner as Static De-List Bids as described in Section III.13.2.3.2(b). Where a resource elected pursuant to Section III.13.1.1.2.2.4 or Section III.13.1.4.1.1.2.7 to have the Capacity Supply Obligation and Capacity Clearing Price continue to apply after the Capacity Commitment Period associated with the Forward Capacity Auction in which the offer clears, the capacity associated with any resulting Capacity Supply Obligation may not be subject to a Dynamic De-List Bid in subsequent Forward Capacity Auctions for Capacity Commitment Periods for which the Project Sponsor elected to have the Capacity Supply Obligation and Capacity Clearing Price continue to apply. Where a Lead Market Participant submits any combination of Dynamic De-List Bid, Static De-List Bid, Export Bid, and Administrative Export De-List Bid for a single resource, none of the prices in a set of price-quantity pairs associated with a bid may be the same as any price in any other set of price-quantity pairs associated with another bid for the same resource.

(e) **Repowering**. Offers and bids associated with a resource participating in the Forward Capacity Auction as a New Generating Capacity Resource pursuant to Section III.13.1.1.1.2 (resources previously counted as capacity resources) shall be addressed in the Forward Capacity Auction in accordance with the provisions of this Section III.13.2.3.2(e). The Project Sponsor shall offer such a New Generating Capacity Resource into the Forward Capacity Auction in the same manner and pursuant to the same rules as other New Generating Capacity Resources, as described in Section III.13.2.3.2(a). As long as any capacity is offered from the New Generating Capacity Resource, the amount of capacity offered is the amount that the auctioneer shall include in the aggregate supply curve at the relevant prices, and the quantity of capacity offered from the associated Existing Generating Capacity Resource shall not be included in the aggregate supply curve. If any portion of the New Generating Capacity Resource clears in the Forward Capacity Auction, the associated Existing Generating Capacity Resource shall be permanently de-listed as of the start of the associated Capacity Commitment Period. If at any price, no capacity is offered from the New Generating Capacity Resource, then the auctioneer shall include capacity from the associated Existing Generating Capacity Resource at that price, subject to any bids submitted and accepted in the qualification process for that Existing Generating Capacity Resource pursuant to Section III.13.1.2.5. Bids submitted and accepted in the qualification process for an Existing Generating Capacity Resource pursuant to Section III.13.1.2.5 shall only be entered into the Forward Capacity Auction after the associated New Generating Capacity Resource is fully withdrawn (that is, the Forward Capacity Auction reaches a price at which the resource's New Capacity Offer is zero capacity), and shall only then be subject to the reliability review described in Section III.13.2.5.2.5.

(f) **Conditional Qualified New Resources.** Offers associated with a resource participating in the Forward Capacity Auction as a Conditional Qualified New Resource pursuant to Section III.13.1.1.2.3(f) shall be addressed in the Forward Capacity Auction in accordance with the provisions of this Section III.13.2.3.2(f). The Project Sponsor shall offer such a Conditional Qualified New Resource into the Forward Capacity Auction in the same manner and pursuant to the same rules as other New Generating Capacity Resources, as described in Section III.13.2.3.2(a). An offer from at most one resource at a Conditional Qualified New Resource's location will be permitted to clear (receive a Capacity Supply Obligation for the associated Capacity Commitment Period) in the Forward Capacity Auction. As long as a positive quantity is offered at the End-of-Round Price in the final round of the Forward Capacity Auction by the resource having a higher queue priority at the Conditional Qualified New Resource's location, as described in Section III.13.1.1.2.3(f), then no capacity from the Conditional Qualified New Resource shall clear. If at any price greater than or equal to the End-of-Round Price in the final round of the Forward Capacity Auction, zero quantity is offered from the resource having higher queue priority at the Conditional Qualified New Resource's location, as described in Section III.13.1.1.2.3(f), then the auctioneer shall consider capacity offered from the Conditional Qualified New Resource in the determination of clearing, including the application of Section III.13.2.7.

(g) **Mechanics**. Offers and bids that may be submitted during a round of the Forward Capacity Auction must be received between the starting time and ending time of the round, as announced by the auctioneer in advance. The ISO at its sole discretion may authorize a participant in the auction to complete or correct its submission after the ending time of a round, but only if the participant can demonstrate to the ISO's satisfaction that the participant was making reasonable efforts to complete a valid offer submission before the ending time of the round, and only if the ISO determines that allowing the completion or correction will not unreasonably disrupt the auction process. All decisions by the ISO concerning whether or not a participant may complete or correct a submission after the ending time of a round are final.

III.13.2.3.3. Step 3: Determination of the Outcome of Each Round.

The auctioneer shall use the offers and bids for the round as described in Section III.13.2.3.2 to determine the aggregate supply curves for the New England Control Area and for each modeled Capacity Zone included in the round.

The aggregate supply curve for the New England Control Area, the Total System Capacity, shall reflect at each price the sum of the following:

(1) the amount of capacity offered in all Capacity Zones modeled as import-constrained Capacity Zones at that price (excluding capacity offered from New Import Capacity Resources and Existing Import Capacity Resources);

(2) the amount of capacity offered in the Rest-of-Pool Capacity Zone at that price (excluding capacity offered from New Import Capacity Resources and Existing Import Capacity Resources);

(3) for each Capacity Zone modeled as an export-constrained Capacity Zone, the lesser of:

  (i) the amount of capacity offered in the Capacity Zone at that price (including the amount of capacity offered from New Import Capacity Resources and Existing Import Capacity Resources for each interface between the New England Control Area and an external Control Area mapped to the export-constrained Capacity Zone up to that interface's approved capacity transfer limit (net of tie benefits)), or;

  (ii) the amount of capacity determined by the Capacity Zone Demand Curve at zero minus that price, and;

(4) for each interface between the New England Control Area and an external Control Area mapped to an import-constrained Capacity Zone or the Rest-of-Pool Capacity Zone, the lesser of:

  (i) that interface's approved capacity transfer limit (net of tie benefits), or;

  (ii) the amount of capacity offered from New Import Capacity Resources and Existing Import Capacity Resources.

In computing the Total System Capacity, capacity associated with any New Capacity Offer at any price greater than the Forward Capacity Auction Starting Price will not be included in the tally of total capacity at the Forward Capacity Auction Starting Price for that Capacity Zone. On the basis of these aggregate supply curves, the auctioneer shall determine the outcome of the round for each modeled Capacity Zone as follows:

(a) **Import-Constrained Capacity Zones.**

For a Capacity Zone modeled as an import-constrained Capacity Zone, if either of the following two conditions is met during the round:

(1) the aggregate supply curve for the import-constrained Capacity Zone, adjusted as necessary in accordance with Section III.13.2.6 (Capacity Rationing Rule), equals or is less than the quantity determined by the Capacity Zone Demand Curve at the difference between the End-of-Round Price and the price specified by the System-Wide Capacity Demand Curve (at a quantity no less than Total System Capacity at the Start-of-Round Price), or;

(2) the Forward Capacity Auction is concluded for the Rest-of-Pool Capacity Zone;

then the Forward Capacity Auction for that Capacity Zone is concluded and such Capacity Zone will not be included in further rounds of the Forward Capacity Auction.

The Capacity Clearing Price for that Capacity Zone shall be set at the greater of: (1) the sum of the price specified by the Capacity Zone Demand Curve at the amount of capacity equal to the total amount that is awarded a Capacity Supply Obligation in the import-constrained Capacity Zone, and the Capacity Clearing Price for the Rest-of-Pool Capacity Zone, or; (2) the highest price of any offer or bid for a resource in the Capacity Zone that is awarded a Capacity Supply Obligation, subject to the other provisions of this Section III.13.2.

If neither of the two conditions above are met in the round, then that Capacity Zone will be included in the next round of the Forward Capacity Auction.

(b) **Rest-of-Pool Capacity Zone**.

If the Total System Capacity at the End-of-Round Price, adjusted as necessary in accordance with Section III.13.2.6 (Capacity Rationing Rule), and adjusted to include the additional supply in the import-constrained Capacity Zone that may be cleared at a higher price, equals or is less than the amount of capacity determined by the System-Wide Capacity Demand Curve, then the Forward Capacity Auction for the Rest-of-Pool Capacity Zone is concluded and the Rest-of-Pool Capacity Zone will not be included in further rounds of the Forward Capacity Auction.

The Capacity Clearing Price for the Rest-of-Pool Capacity Zone shall be set at the highest price at which the Total System Capacity is less than or equal to the amount of capacity determined by the System-Wide Capacity Demand Curve, subject to the other provisions of this Section III.13.2.

If the Forward Capacity Auction for the Rest-of-Pool Capacity Zone is not concluded then the Rest-of-Pool Capacity Zone will be included in the next round of the Forward Capacity Auction, and the auctioneer shall publish the Total System Capacity at the End-of-Round Price, adjusted to include the additional supply in the import-constrained Capacity Zone that may be cleared at a higher price, less the amount of capacity determined by the System-Wide Capacity Demand Curve at the End-of-Round Price.

(c) **Export-Constrained Capacity Zones**.

For a Capacity Zone modeled as an export-constrained Capacity Zone, if all of the following conditions are met during the round:

(1) the aggregate supply curve for the export-constrained Capacity Zone, adjusted as necessary in accordance with Section III.13.2.6 (Capacity Rationing Rule), is equal to or less than the maximum amount of capacity determined by the Capacity Zone Demand Curve at a price of zero;

(2) in the case of a nested Capacity Zone, the Forward Capacity Auction is concluded for the Capacity Zone within which the nested Capacity Zone is located, and;

(3) the Forward Capacity Auction is concluded for the Rest-of-Pool Capacity Zone;

then the Forward Capacity Auction for that Capacity Zone is concluded and such Capacity Zone will not be included in further rounds of the Forward Capacity Auction.

The Capacity Clearing Price for an export-constrained Capacity Zone that is not a nested export-constrained Capacity Zone shall be set at the greater of:

(1) the sum of:

(i) the price specified by the Capacity Zone Demand Curve at the amount of capacity equal to the total amount that is awarded a Capacity Supply Obligation in that Capacity Zone; and

(ii) the Capacity Clearing Price for the Rest-of-Pool Capacity Zone.

or;

(2) the highest price of any offer or bid for a resource in the Capacity Zone that is awarded a Capacity Supply Obligation, and subject to the other provisions of this Section III.13.2.

The Capacity Clearing Price for a nested export-constrained Capacity Zone shall be set at the greater of:

(1) the sum of:

(i) the price specified by the Capacity Zone Demand Curve at the amount of capacity equal to the total amount that is awarded a Capacity Supply Obligation in that Capacity Zone; and

(ii) the Capacity Clearing Price for the Capacity Zone in which the nested Capacity Zone is located,

or;

(2) the highest price of any offer or bid for a resource in the Capacity Zone that is awarded a Capacity Supply Obligation, subject to the other provisions of this Section III.13.2.

If all of the conditions above are not satisfied in the round, then the auctioneer shall publish the quantity of excess supply in the export-constrained Capacity Zone at the End-of-Round Price (the amount of capacity offered at the End-of-Round Price in the export-constrained Capacity Zone minus the maximum amount of capacity determined by the Capacity Zone Demand Curve at a price of zero) and that Capacity Zone will be included in the next round of the Forward Capacity Auction.

(d) **Treatment of Import Capacity.** Where the amount of capacity offered from New Import Capacity Resources and Existing Import Capacity Resources over an interface between the New England Control Area and an external Control Area is less than or equal to that interface's approved capacity transfer limit (net of tie benefits, or net of HQICC in the case of the Phase I/II HVDC-TF), then the capacity offers from those resources shall be treated as capacity offers in the modeled Capacity Zone associated with that interface. Where the amount of capacity offered from New Import Capacity Resources and Existing Import Capacity Resources over an interface between the New England Control Area and an external Control Area is greater than that interface's approved capacity transfer limit (net of tie benefits, or net of HQICC in the case of the Phase I/II HVDC-TF), then the following provisions shall apply (separately for each such interface):

(i) For purposes of determining which capacity offers from the New Import Capacity Resources and Existing Import Capacity Resources over the interface shall clear and at what price, the offers over the interface shall be treated in the descending-clock auction as if they comprised a separately-modeled export-constrained capacity zone, with an aggregate supply curve consisting of the offers from the New Import Capacity Resources and Existing Import Capacity Resources over the interface.

(ii) The amount of capacity offered over the interface that will be included in the aggregate supply curve of the modeled Capacity Zone associated with the interface shall be the lesser of the following two quantities: the amount of capacity offered from New Import Capacity Resources

and Existing Import Capacity Resources over the interface; and the interface's approved capacity transfer limit (net of tie benefits, or net of HQICC in the case of the Phase I/II HVDC-TF).

(iii) The Forward Capacity Auction for New Import Capacity Resources and Existing Import Capacity Resources over the interface is concluded when the following two conditions are both satisfied: the amount of capacity offered from New Import Capacity Resource and Existing Import Capacity Resources over the interface is less than or equal to the interface's approved capacity transfer limit (net of tie benefits, or net of HQICC in the case of the Phase I/II HVDC-TF); and the Forward Capacity Auction is concluded in the modeled Capacity Zone associated with the interface.

(e) **Treatment of Export Capacity.** Any Export Bid or any Administrative Export De-List Bid that is used to export capacity through an export interface connected to an import-constrained Capacity Zone from another Capacity Zone, or through an export interface connected to the Rest-of-Pool Capacity Zone from an export-constrained Capacity Zone in the Forward Capacity Auction will be modeled in the Capacity Zone where the export interface that is identified in the Existing Capacity Qualification Package is located. The Export Bid or Administrative Export De-List Bid clears in the Capacity Zone where the Export Bid or Administrative Export De-List Bid is modeled.

(i) Then the MW quantity equal to the relevant Export Bid or Administrative Export De-List Bid from the resource associated with the Export Bid or Administrative Export De-List Bid will be de-listed in the Capacity Zone where the resource is located. If the export interface is connected to an import-constrained Capacity Zone, the MW quantity procured will be in addition to the amount of capacity determined by the Capacity Zone Demand Curve for the import-constrained Capacity Zone.

(ii) If the Export Bid or Administrative Export De-List Bid does not clear, then the resource associated with the Export Bid or Administrative Export De-List Bid will not be de-listed in the Capacity Zone where the resource is located.

III.13.2.3.4. Determination of Final Capacity Zones.

(a) For all Forward Capacity Auctions up to and including the sixth Forward Capacity Auction (for the Capacity Commitment Period beginning June 1, 2015), after the Forward Capacity Auction is concluded for all modeled Capacity Zones, the final set of distinct Capacity Zones that will be used for all

purposes associated with the relevant Capacity Commitment Period, including for the purposes of reconfiguration auctions and Capacity Supply Obligation Bilaterals, shall be those having distinct Capacity Clearing Prices as a result of constraints between modeled Capacity Zones binding in the running of the Forward Capacity Auction. Where a modeled constraint does not bind in the Forward Capacity Auction, and as a result adjacent modeled Capacity Zones clear at the same Capacity Clearing Price, those modeled Capacity Zones shall be a single Capacity Zone used for all purposes of the relevant Capacity Commitment Period, including for the purposes of reconfiguration auctions and Capacity Supply Obligation Bilaterals.

(b) For all Forward Capacity Auctions beginning with the seventh Forward Capacity Auction (for the Capacity Commitment Period beginning June 1, 2016) the final set of distinct Capacity Zones that will be used for all purposes associated with the relevant Capacity Commitment Period, including for the purposes of reconfiguration auctions and Capacity Supply Obligation Bilaterals, shall be those described in Section III.12.4.

III.13.2.4. Forward Capacity Auction Starting Price and the Cost of New Entry.
The Forward Capacity Auction Starting Price is max [1.6 multiplied by Net CONE, CONE]. References in this Section III.13 to the Forward Capacity Auction Starting Price shall mean the Forward Capacity Auction Starting Price for the Forward Capacity Auction associated with the relevant Capacity Commitment Period.

CONE for the Forward Capacity Auction for the Capacity Commitment Period beginning on June 1, 2021 is $11.35/kW-month.

Net CONE for the Forward Capacity Auction for the Capacity Commitment Period beginning on June 1, 2021 is $8.04/kW-month.

CONE and Net CONE shall be recalculated for the Capacity Commitment Period beginning on June 1, 2025 and no less often than once every three years thereafter. Whenever these values are recalculated, the ISO will review the results of the recalculation with stakeholders and the new values will be filed with the Commission prior to the Forward Capacity Auction in which the new value is to apply.

Between recalculations, CONE and Net CONE will be adjusted for each Forward Capacity Auction pursuant to Section III.A.21.1.2(e). Prior to applying the annual adjustment for the Capacity

Commitment Period beginning on June 1, 2019, Net CONE will be reduced by $0.43/kW-month to reflect the elimination of the PER adjustment. The adjusted CONE and Net CONE values will be published on the ISO's web site.

III.13.2.5. Treatment of Specific Offer and Bid Types in the Forward Capacity Auction.

III.13.2.5.1. Offers from New Generating Capacity Resources, New Import Capacity Resources, and New Demand Capacity Resources.

A New Capacity Offer (other than one from a Conditional Qualified New Resource) clears (receives a Capacity Supply Obligation for the associated Capacity Commitment Period) in the Forward Capacity Auction if the Capacity Clearing Price is greater than or equal to the price specified in the offer, except possibly as a result of the Capacity Rationing Rule described in Section III.13.2.6. An offer from a Conditional Qualified New Resource clears (receives a Capacity Supply Obligation for the associated Capacity Commitment Period) in the Forward Capacity Auction, except possibly as a result of the Capacity Rationing Rule described in Section III.13.2.6, if all of the following conditions are met: (i) the Capacity Clearing Price is greater than or equal to the price specified in the offer; (ii) capacity from that resource is considered in the determination of clearing as described in Section III.13.2.3.2(f); and (iii) such offer minimizes the costs for the associated Capacity Commitment Period, subject to Section III.13.2.7.7(c).

The amount of capacity that receives a Capacity Supply Obligation through the Forward Capacity Auction shall not exceed the quantity of capacity offered from the New Generating Capacity Resource, New Import Capacity Resource, or New Demand Capacity Resource at the Capacity Clearing Price.

III.13.2.5.2. Bids and Offers from Existing Generating Capacity Resources, Existing Import Capacity Resources, and Existing Demand Capacity Resources.

III.13.2.5.2.1. Permanent De-List Bids and Retirement De-List Bids.

(a) Except as provided in Section III.13.2.5.2.5, a Permanent De-List Bid, Retirement De-List Bid or Proxy De-List Bid clears in the Forward Capacity Auction (does not receive a Capacity Supply Obligation) if the Capacity Clearing Price is less than or equal to the price specified in the bid, except possibly as a result of the Capacity Rationing Rule described in Section III.13.2.6.

(b) Unless the capacity has been retained for reliability pursuant to Section III.13.2.5.2.5, if all or part of a resource with a Permanent De-List Bid or Retirement De-List Bid does not clear in the Forward Capacity Auction (receives a Capacity Supply Obligation), the Lead Market Participant shall enter the uncleared portion of the bid into the qualification process for the following Forward Capacity Auction as described in Section III.13.1.2.3.1.5.

(c) If the Capacity Clearing Price is greater than the price specified in a de-list bid submitted by a Lead Market Participant that elected conditional treatment for the de-list bid pursuant to Section III.13.1.2.4.1(b), and there is an associated Proxy De-List Bid that does not clear (receives a Capacity Supply Obligation), the resource will receive a Capacity Supply Obligation at the Capacity Clearing Price.

(d) The process by which the primary auction is cleared (but not the compilation of offers and bids pursuant to Sections III.13.2.3.1 and III.13.2.3.2) will be repeated after the substitution auction is completed if one of the following conditions is met: (1) if any Proxy De-List Bid entered as a result of a Lead Market Participant electing to retire pursuant to Section III.13.1.2.4.1(a) does not clear (receives a Capacity Supply Obligation) in the first run of the primary auction-clearing process and retains some portion of its Capacity Supply Obligation in the substitution auction; or (2) if any Proxy De-List Bid entered as a result of a Lead Market Participant electing conditional treatment pursuant to Section III.13.1.2.4.1(b) does not clear (receives a Capacity Supply Obligation) in the first run of the primary auction-clearing process, the de-list bid submitted by the Lead Market Participant is at or above the Capacity Clearing Price, and the Proxy De-List Bid retains some portion of its Capacity Supply Obligation in the substitution auction. The second run of the primary auction-clearing process: (i) excludes all Proxy De-List Bids, (ii) includes the offers and bids of resources compiled pursuant to Section III.13.2.3.2 that did not receive a Capacity Supply Obligation in the first run of the primary auction-clearing process, excluding the offers, or portion thereof, associated with resources that acquired a Capacity Supply Obligation in the substitution auction, and (iii) includes the capacity of resources, or portion thereof, that retain a Capacity Supply Obligation after the first run of the primary auction-clearing process and the substitution auction. The second run of the primary auction-clearing process shall not affect the Capacity Clearing Price of the Forward Capacity Auction (which is established by the first run of the primary auction-clearing process).

(e) Resources (other than those still subject to a multi-year Capacity Commitment Period election as described in Sections III.13.1.1.2.2.4 and III.13.1.4.1.1.2.7) that receive a Capacity Supply Obligation as a

result of the first run of the primary auction-clearing process shall be paid the Capacity Clearing Price during the associated Capacity Commitment Period. Where the second run of the primary auction-clearing process procures additional capacity, the resulting price, paid during the associated Capacity Commitment Period (and subsequent Capacity Commitment Periods, as elected pursuant to Section III.13.1.1.2.2.4 or Section III.13.1.4.1.1.2.7) to the additionally procured capacity, shall be equal to or greater than the adjusted price resulting from the first run of the primary auction-clearing process for that Capacity Zone.

III.13.2.5.2.2. **Static De-List Bids and Export Bids**.

Except as provided in Section III.13.2.5.2.5, a Static De-List Bid or an Export Bid clears in the Forward Capacity Auction (does not receive a Capacity Supply Obligation for the associated Capacity Commitment Period) if the Capacity Clearing Price is less than or equal to the price specified in the bid, except possibly as a result of the Capacity Rationing Rule described in Section III.13.2.6.

III.13.2.5.2.3. **Dynamic De-List Bids.**

A Dynamic De-List Bid clears in the Forward Capacity Auction (does not receive a Capacity Supply Obligation for the associated Capacity Commitment Period) if the Capacity Clearing Price is less than or equal to the price specified in the bid, except possibly as a result of the Capacity Rationing Rule described in Section III.13.2.6. If more Dynamic De-List Bids are submitted at a price than are needed to clear the market, such Dynamic De-List Bids shall be cleared pro-rata, but in no case less than a resource's Rationing Minimum Limit.

III.13.2.5.2.4. **Administrative Export De-List Bids**.

An Administrative Export De-List Bid clears in the Forward Capacity Auction (does not receive a Capacity Supply Obligation for the associated Capacity Commitment Period) regardless of the Capacity Clearing Price.

III.13.2.5.2.5. **Reliability Review**.

The ISO shall review each Retirement De-List Bid, Permanent De-List Bid, Static De-List Bid, Export Bid, Administrative Export De-List Bid, Dynamic De-List Bid, and substitution auction demand bid to determine whether the capacity associated with that bid is needed for reliability reasons during the Capacity Commitment Period associated with the Forward Capacity Auction; Proxy De-List Bids shall not be reviewed.

(a) The reliability review of de-list bids will be conducted in descending price order using the price as finalized during qualification or as otherwise directed by the Commission. De-list bids with the same price will be reviewed in the order that produces the least negative impact to reliability; where bids are the same price and provide the same impact to reliability, they will be reviewed based on their submission time. If de-list bids with the same price are from a single generating station, they will be reviewed in an order that seeks to provide (1) the least-cost solution under Section III.13.2.5.2.5.1(d) and (2) the minimum aggregate quantity required for reliability from the generating station. The reliability review of substitution auction demand bids that would otherwise clear will be conducted in order beginning with the resource whose cleared bids contribute the greatest amount to social surplus. The capacity associated with a bid shall be deemed needed for reliability reasons if the absence of the capacity would result in the violation of any NERC or NPCC criteria, or ISO New England System Rules. Bids shall only be rejected pursuant to this Section III.13.2.5.2.5 for the sole purpose of addressing a local reliability issue, and shall not be rejected solely on the basis that acceptance of the bid may result in the procurement of less capacity than the Installed Capacity Requirement (net of HQICCs) or the Local Sourcing Requirement for a Capacity Zone.

(b) If a Retirement De-List Bid, Permanent De-List Bid, Static De-List Bid, Export Bid, Administrative Export De-List Bid, or Dynamic De-List Bid would otherwise clear in the Forward Capacity Auction, but the ISO has determined that some or all of the capacity associated with the de-list bid is needed for reliability reasons, then the de-list bid having capacity needed for reliability will not clear in the Forward Capacity Auction. If the ISO has determined that some or all of the capacity associated with a substitution auction demand bid that would otherwise clear is needed for reliability reasons, then the entire demand bid will not be further included in the substitution auction.

(c) The Lead Market Participant shall be notified that its bid did not clear for reliability reasons at the later of: (i) immediately after the end of the Forward Capacity Auction round in which the auction price reaches the price of the de-list bid; or (ii) as soon as practicable after the time at which the ISO has determined that the bid must be rejected for reliability reasons. In no event, however, shall a Lead Market Participant be notified that a bid submitted pursuant to Section III.13.1.2.5 and accepted in the qualification process for an Existing Generating Capacity Resource did not clear for reliability reasons if the associated New Generating Capacity Resource remains in the Forward Capacity Auction. In such a case, the Lead Market Participant shall be notified that its bid did not clear for reliability reasons at the later of: (i) immediately after the end of the Forward Capacity Auction round in which the auction price reaches the price of the bid; (ii) immediately after the end of the Forward Capacity Auction round in

which the associated New Generating Capacity Resource is fully withdrawn (that is, the Forward Capacity Auction reaches a price at which the resource's New Capacity Offer is zero capacity); or (iii) as soon as practicable after the time at which the ISO has determined that the bid must be rejected for reliability reasons.

(d) A resource that has a de-list bid rejected for reliability reasons shall be compensated pursuant to the terms set out in Section III.13.2.5.2.5.1 and shall have a Capacity Supply Obligation as described in Section III.13.6.1.

(e) The ISO shall review the results of each annual reconfiguration auction and determine whether the reliability need which caused the ISO to reject the de-list bid has been met through the annual reconfiguration auction. The ISO may also attempt to address the reliability concern through other reasonable means (including transmission enhancements).

(f) If the reliability need that caused the ISO to reject a de-list bid is met through a reconfiguration auction or other means, the resource shall retain its Capacity Supply Obligation through the end of the Capacity Commitment Period for which it was retained for reliability (provided that resources that have Permanent De-List Bids or Retirement De-List Bids rejected for reliability shall be permanently de-listed or retired as of the first day of the subsequent Capacity Commitment Period (or earlier if the resource sheds the entirety of the Capacity Supply Obligation as described in Section III.13.2.5.2.5.3(a)(ii) or Section III.13.2.5.2.5.3(b)(ii))).

(g) If a Permanent De-List Bid or a Retirement De-List Bid is rejected for reliability reasons, and the reliability need is not met through a reconfiguration auction or other means, that resource, or portion thereof, as applicable, is no longer eligible to participate as an Existing Capacity Resource in any reconfiguration auction, Forward Capacity Auction or Capacity Supply Obligation Bilateral for that and subsequent Capacity Commitment Periods. If the resource, or portion thereof, continues to be needed for reliability reasons, it shall be counted as capacity in the Forward Capacity Auction and shall be compensated as described in Section III.13.2.5.2.5.1.

(h) The ISO shall review with the Reliability Committee (i) the status of any prior rejected de-list bids reported to the Commission in an FCA results filing pursuant to Section 13.8.2, and (ii) the status of any Retirement De-List Bid or Permanent De-List Bid that has been rejected for reliability reasons and

has elected to continue to operate, prior to the New Capacity Qualification Deadline in accordance with Section 4.1(c) of Attachment K of the ISO OATT.

If an identified reliability need results in the rejection of a Retirement De-List Bid, Permanent De-List Bid, Export Bid, Administrative Export De-List Bid, Static De-List Bid, or Dynamic De-List Bid while executing an FCA, the ISO shall (i) review each specific reliability need with the Reliability Committee in accordance with the timing provided for in the ISO New England Operating Documents and, (ii) update the current system Needs Assessments pursuant to Section 4.1(c) of Attachment K of the ISO OATT. This review and update will follow ISO's filing of the FCA results with the Commission pursuant to Section 13.8.2.

III.13.2.5.2.5A Fuel Security Reliability Review

(a) This Section III.13.2.5.2.5A will remain in effect for the 2022/23~~,~~ and 2023/24 ~~and 2024/25~~ Capacity Commitment Periods, after which this Section III.13.2.5.2.5A will sunset.

(b) This Section III.13.2.5.2.5A will apply to (i) Retirement De-List Bids, (ii) substitution auction demand bids, and (iii) bilateral transactions and reconfiguration auctions demand bids submitted by an Existing Generating Capacity Resource that has been identified as being needed for fuel security during a Forward Capacity Auction. Terms set out in this Section III.13.2.5.2.5A will apply only for the period and resources described within this Section III.13.2.5.2.5A. Where the terms and conditions in this Section III.13.2.5.2.5A differ from terms otherwise set out in Section III.13, the terms of this Section III.13.2.5.2.5A will control for the period and circumstances described in Section III.13.2.5.2.5A.

(c) A fuel security reliability review for the Forward Capacity Market will be performed pursuant to Appendix L to Section III of the Tariff, and in accordance with the inputs and methodology set out to establish the fuel security reliability standard in Appendix I of Planning Procedure No. 10.

(d) For fuel security reliability reviews performed for the primary Forward Capacity Auction, the fuel security reliability review will be performed after the Existing Capacity Retirement Deadline and conducted in descending price order using the price as submitted in the Retirement De-List Bids. Bids with the same price will be reviewed in the order that produces the least negative impact to reliability. Where multiple bids have the same price and the retirement of the Existing Generating Capacity Resources would have the same impact to reliability, they will be reviewed based on their submission

time. If bids with the same price are from a single generating station, they will be reviewed in an order that seeks to provide (1) the least-cost solution under Section III.13.2.5.2.5.1(d), and (2) the minimum aggregate quantity required for reliability from the generating station. An Existing Generating Capacity Resource may be needed for both fuel security and for transmission security pursuant to Section III.13.2.5.2.5. The fuel security reliability review will be performed in advance of the reliability review for transmission security. Where an Existing Generating Capacity Resource is needed for both fuel security reasons pursuant to this Section III.13.2.5.2.5A, and transmission security reliability reasons pursuant to Section III.13.2.5.2.5, the generator will be retained for fuel security for purposes of cost allocation.

(e) If an Existing Generating Capacity Resource is identified as being needed for fuel security reasons, and the reliability need is not met through a reconfiguration auction or other means, that resource, or portion thereof, as applicable may not participate in Annual Reconfiguration Auctions for the Capacity Commitment Period(s) for which it is needed for fuel security, or earlier 2022/23~~,~~ and 2023/24 ~~and 2024/25~~ Capacity Commitment Periods. Such an Existing Generating Capacity Resource that is identified as being needed for fuel security may participate in monthly bilateral transactions and monthly reconfiguration auctions, but may not submit monthly bilateral transactions for December, January or February, or demand bids for the December, January, or February monthly reconfiguration auctions for any period for which they have been identified as being needed for fuel security.

(f) Participants that have submitted a Retirement De-List Bid will be notified by ISO New England if their resource is needed for fuel security reliability reasons no later than 90 days after the Existing Capacity Retirement Deadline. Participants that have submitted a substitution auction demand bid, and where the demand bid has been rejected for reliability reasons, will be notified after the relevant Forward Capacity Auction has been completed.

(g) Where a Retirement De-List Bid would otherwise clear in the Forward Capacity Auction, but the ISO has determined that some or all of the capacity associated with the de-list bid is needed for fuel security reliability reasons, the provisions of III.13.2.5.2.5(b) shall apply.

(h) Existing Generating Capacity Resources that have had their Retirement De-list Bid rejected for fuel security reliability reasons and that do not elect to unconditionally or conditionally retire shall be eligible for compensation pursuant to Section III.13.2.5.2.5.1, except that the difference between payments based on resource de-list bids or cost-of-service compensation as detailed in Section III.13.2.5.2.5.1 and

payments based on the Capacity Clearing Price for the Forward Capacity Market under this Section III.13.2.5.2.5.1 shall be allocated on a regional basis to Real Time Load Obligation, excluding Real-Time Load Obligation associated with Dispatchable Asset Related Demand Resources (DARD Pumps and other electric storage based DARDs) and Real-Time Load Obligation associated with Coordinated External Transactions, allocated and collected over a 12 month period. Resources that that are identified as needed for fuel security reliability reasons will have their capacity entered into the Forward Capacity Auction pursuant to III.13.2.5.2.5(g) and III.13.2.3.2(b).

(i) Where an Existing Generating Capacity Resource elects a cost-of-service agreement pursuant to Section III.13.2.5.2.5.1 to address a fuel security reliability need, the term of such a cost-of-service agreement may not exceed two years, including renewal through evergreen provisions.~~ A cost-of-service agreement entered into for the 2024/2025 Capacity Commitment Period shall be limited to a total duration of one year.~~

(j) The ISO shall perform an annual reevaluation of any Existing Generating Capacity Resources retained for reliability under this provision. If a resource associated with a Retirement De-List Bid that was rejected for reliability reasons pursuant to this section, is found to no longer be needed for fuel security, and is not needed for another reliability reason pursuant to Section III.13.2.5.2.5, the resource will be retired from the system as described in Section III.13.2.5.2.5.3(a)(1). In no case will a resource retained for fuel security be retained for fuel security beyond June 1, 2024~~5~~.

(k) The ISO will review Retirement De-List Bids rejected for fuel security reliability reasons with the Reliability Committee in the same manner as described in Section III.13.2.5.2.5(h).

III.13.2.5.2.5.1. Compensation for Bids Rejected for Reliability Reasons.

(a) In cases where a Static De-List Bid, Export Bid, Administrative Export De-List Bid, Dynamic De-List Bid, partial Permanent De-List Bid, or partial Retirement De-List Bid has been rejected for reliability reasons pursuant to Sections III.13.1.2.3.1.5.1 or III.13.2.5.2.5, the resource will be paid by the ISO in the same manner as all other capacity resources, except that payment shall be made on the basis of its de-list bid as accepted for the Forward Capacity Auction for the relevant Capacity Commitment Period instead of the Forward Capacity Market Clearing Price. Under this Section, accepted Dynamic De-List Bids filed with the Commission as part of the FCA results filing are subject to review and approval by the Commission pursuant to the "just and reasonable" standard of Section 205 of the Federal Power Act. If a resource with a partial Permanent De-List Bid or partial Retirement De-List Bid continues to be needed for reliability in Capacity Commitment Periods following the Capacity Commitment Period for which the partial Permanent De-List Bid or partial Retirement De-List Bid was rejected, payment will continue to be pursuant to this Section III.13.2.5.2.5.1(a).

(b) In cases where a Permanent De-List Bid or a Retirement De-List Bid for the capacity of an entire resource has been rejected for reliability reasons pursuant to Section III.13.1.2.3.1.5.1 or III.13.2.5.2.5, the resource will be paid either (i) in the same manner as all other capacity resources, except that payment shall be made on the basis of its Commission-approved Permanent De-List Bid or Commission-approved Retirement De-List Bid for the relevant Capacity Commitment Period instead of the Forward Capacity Market Clearing Price or (ii) under the terms of a cost-of-service agreement pursuant to Section III, Appendix I. Resources must notify the ISO of their election within six months after the ISO files the results of the relevant Forward Capacity Auction with the Commission. A resource that has had a Permanent De-List Bid or Retirement De-List Bid rejected for reliability reasons and does not notify the ISO of its election as described in this paragraph will be paid on the basis of the resource's Commission-approved Permanent De-List Bid or Commission-approved Retirement De-List Bid. Cost-of-service agreements must be filed with and approved by the Commission, and cost-of-service compensation may not commence until the Commission has approved the use of cost-of-service rates for the unit in question or has accepted the use of the cost-of-service rates subject to refund while the rate is reviewed. In no event will payment under the cost-of-service agreement start prior to the start of the relevant Capacity Commitment Period for which the Permanent De-List Bid or Retirement De-List Bid was submitted. If a resource continues to be needed for reliability in Capacity Commitment Periods following the Capacity Commitment Period for which the Permanent De-List Bid or Retirement De-List Bid was rejected, payment will continue to be pursuant to this Section III.13.2.5.2.5.1(b). Resources that elect payment based on the Commission-approved Permanent De-List Bid or Commission-approved Retirement De-List Bid may file with the Commission pursuant to Section 205 of the Federal Power Act to update its Permanent De-List Bid or Retirement De-List Bid if the unit is retained for reliability for a period longer than the Capacity Commitment Period for which the Permanent De-List Bid or Retirement De-List Bid was originally submitted.

(c) The difference between payments based on resource de-list bids or cost-of-service compensation as detailed in this Section III.13.2.5.2.5.1 and payments based on the market clearing price for the Forward Capacity Market under this Section III.13.2.5.2.5.1 shall be allocated to Regional Network Load within the affected Reliability Region.

(d) **Compensation for Existing Generating Capacity Resources at Stations with Common Costs that are Retained for Reliability**. If a Static De-List Bid, Permanent De-List Bid, or Retirement De-List Bid from an Existing Generating Capacity Resource that is associated with a Station having Common Costs is rejected for reliability reasons, the Existing Generating Capacity Resource will be paid as follows: (i) if one or more Existing Generating Capacity Resources at the Station assume a Capacity Supply Obligation through the normal clearing of the Forward Capacity Auction and one or more Existing Generating Capacity Resources are retained for reliability, then the Existing Generating Capacity Resources retained for reliability will be paid the sum of the Asset-Specific Going Forward Costs for the assets comprising that Existing Generating Capacity Resource; or (ii) if no Existing Generating Capacity Resources at the Station assumes a Capacity Supply Obligation through the normal clearing of the Forward Capacity Auction and one or more Existing Generating Capacity Resources are retained for reliability, then each Existing Generating Capacity Resource retained for reliability will be paid the sum of the Asset-Specific Going Forward Costs for the assets associated with that Existing Generating Capacity Resource plus a portion of the Station Going Forward Common Costs (such that the full amount of Station Going Forward Common Costs are allocated to the Existing Generating Capacity Resources retained for reliability).

(e) If ISO-NE is a party to a cost-of-service agreement filed after January 1, 2019 that changes any resource performance-related obligations contained in Section III, Appendix I (provided that those obligations are different than the obligations of an Existing Generating Capacity Resource with a Capacity Supply Obligation), no later than 30 days after such agreement is filed with the Commission, ISO-NE shall provide to stakeholders quantitative and qualitative information on the need for, and the impacts of, the proposed changes.

III.13.2.5.2.5.2. Incremental Cost of Reliability Service From Permanent De-List Bid or Retirement De-List Bid Resources.

In cases where an Existing Generating Capacity Resource or Existing Demand Capacity Resource has had a Permanent De-List Bid or Retirement De-List Bid for the entire resource rejected for reliability reasons pursuant to Sections III.13.1.2.3.1.5.1 or III.13.2.5.2.5, does not elect to retire pursuant to Section III.13.1.2.3.1.5.1(d), and must make a capital improvement to the unit to remain in operation in order to continue to operate to meet the reliability need identified by the ISO, the resource may make application to the Commission pursuant to Section 205 of the Federal Power Act to receive just and reasonable compensation of the capital investment pursuant to the following:

(a) **Notice to State Utility Commissions, the ISO and Stakeholder Committees of Expectation that a Capital Expense will be Necessary to Meet the Reliability Need Identified by the ISO**: A resource seeking to avail itself of the recovery mechanism provided in this Section must notify the state utility commissions in the states where rate payers will fund the capital improvement, the ISO, and the Participants Committee of its intent to make the capital expenditure and the need for the expenditure. This notification must be made at least 120 days prior to the resource making the capital expenditure.

(b) **Required Showing Made to the Federal Energy Regulatory Commission**: In order to receive just and reasonable compensation for a capital expenditure under this Section, a resource must file an explanation of need with the Commission that explains why the capital expenditure is necessary in order to meet the reliability need identified by the ISO. This showing must demonstrate that the expenditure is reasonably determined to be the least-cost commercially reasonable option consistent with Good Utility Practice to meet the reliability need identified by the ISO. If the resource elects cost-of-service treatment pursuant to Section III.13.2.5.2.5.1(b), the Incremental Cost of Reliability Service filing described in this Section must be made separately from and may be made in advance of the resource's cost-of-service filing.

(c) **Allocation:** Costs of capital expenditures approved by the Commission under this provision shall be allocated to Regional Network Load within the affected Reliability Region.

III.13.2.5.2.5.3. Retirement and Permanent De-Listing of Resources.

(a)(i) A resource, or portion thereof, will be retired coincident with the commencement of the relevant Capacity Commitment Period, or earlier as described in Section III.13.2.5.2.5.3(a)(ii), if the resource: (1) submitted a Retirement De-List Bid at or above the Forward Capacity Auction Starting Price and was not retained for reliability pursuant to Section III.13.1.2.3.1.5.1; (2) submitted a Permanent De-List Bid or Retirement De-List Bid, elected to retire pursuant to Section III.13.1.2.4.1(a), and was not retained for reliability pursuant to Section III.13.1.2.3.1.5.1; (3) elected conditional treatment pursuant to Section III.13.1.2.4.1(b) for a Retirement De-List Bid with a submitted price at or above the Capacity Clearing Price and was not retained for reliability pursuant to Section III.13.1.2.3.1.5.1; or (4) had a Commission-approved Retirement De-List Bid clear in the Forward Capacity Auction. In the case of a Retirement De-List Bid rejected for reliability, if the reliability need that resulted in the rejection for reliability is met, the resource, or portion thereof, will be retired coincident with the end of Capacity Supply Obligation (or earlier as described in Section III.13.2.5.2.5.3(a)(ii)) unless the Commission directs that the obligation to retire be removed or the retirement date extended as part of an Incremental Cost of Reliability Service

filing made pursuant to Section III.13.2.5.2.5.2. The interconnection rights, or relevant portion thereof, for the resource will terminate and the status of the resource, or portion thereof, will be converted to retired on the date of retirement, consistent with the provisions of Schedules 22 and 23 of the OATT.

(a)(ii) A resource, or portion thereof, that is to be retired pursuant to Section III.13.2.5.2.5.3(a)(i) may retire the resource, or portion thereof, earlier than the Capacity Commitment Period for which its Retirement De-List Bid was submitted if it is able to transfer the relevant Capacity Supply Obligation of the resource to another resource through one or more approved Capacity Supply Obligation Bilateral transactions as described in Section III.13.5.1 or reconfiguration auctions as described in Section III.13.4.1. A resource, or portion thereof, electing to retire pursuant to this provision must notify the ISO in writing of its election to retire and the date of retirement. The interconnection rights, or relevant portion thereof, for the resource will terminate and the status of the resource, or portion thereof, will be converted to retired on the date of retirement, consistent with the provisions of Schedules 22 and 23 of the OATT.

(b)(i) A resource, or portion thereof, will be permanently de-listed from the Forward Capacity Market as of the relevant Capacity Commitment Period, or earlier as described in Section III.13.2.5.2.5.3(b)(ii), if the resource: (1) submitted an Internal Market Monitor-approved Permanent De-List Bid at or above the Forward Capacity Auction Starting Price and was not retained for reliablity pursuant to Section III.13.1.2.3.1.5.1; (2) elected conditional treatment pursuant to Section III.13.1.2.4.1(b) for a Permanent De-List Bid with a submitted price at or above the Capacity Clearing Price and was not retained for reliability pursuant to Section III.13.1.2.3.1.5.1; or (3) had a Commission-approved Permanent De-List Bid clear in the Forward Capacity Auction. The CNR Capability interconnection rights, or relevant portion thereof, for the resource will be adjusted downward to reflect the Permanent De-List Bid, consistent with the provisions of Schedules 22 and 23 of the OATT. A resource that permanently de-lists pursuant to this Section III.13.2.5.2.5.3(b)(i) is precluded from subsequent participation in the Forward Capacity Market unless it qualifies as a New Generating Capacity Resource pursuant to Section III.13.1.1.1.2.

(b)(ii) A resource, or portion thereof, that is to be permanently de-listed pursuant to Section III.13.2.5.2.5.3(b)(i) may be permanently de-listed earlier than the Capacity Commitment Period for which its Permanent De-List Bid was submitted if it is able to transfer the entire Capacity Supply Obligation of the resource to another resource through one or more approved Capacity Supply Obligation Bilateral transactions as described in Section III.13.5.1 or reconfiguration auctions as described in Section III.13.4.

(c) A resource that has never been counted as a capacity resource may retire the asset by notifying the ISO in writing of its election to retire and the date of retirement. The date specified for retirement is subject to the limit for resource inactivity set out in Section III.13.2.5.2.5.3(d). The interconnection rights for the resource will terminate and the status of the resource will be converted to retired on the date of retirement.

(d) A resource that does not operate commercially for a period of three calendar years will be deemed by the ISO to be retired. The interconnection rights for the unit will terminate and the status of the unit will be converted to retired on the date of retirement. Where a generator has submitted an application to repower under Schedule 22 or 23 of the OATT, the current interconnection space will be maintained beyond the three years unless the application under Schedule 22 or 23 is withdrawn voluntarily or by the operation of those provisions. Where an application is withdrawn under Schedule 22 or 23, the three year period will be calculated from the last day of commercial operation of the resource.

III.13.2.6. Capacity Rationing Rule.

Except for Dynamic De-List Bids, Export Bids, and offers from New Import Capacity Resources that are subject to rationing pursuant to Section III.13.1.3.5.8 and Existing Import Capacity Resources that are subject to rationing pursuant to Section III.13.1.3.3.A, offers and bids in the Forward Capacity Auction must clear or not clear in whole, unless the offer or bid specifically indicates that it may be rationed. A resource may elect to be rationed to its Rationing Minimum Limit pursuant to Sections III.13.1.1.2.2.3 and III.13.1.2.1.2. Offers from New Import Capacity Resources and Existing Import Capacity Resources will not be rationed where such rationing would violate any applicable physical minimum flow requirements on the associated interface. Export Bids may elect to be rationed generally, but regardless of such election will always be subject to potential rationing where the associated external interface binds. If more Dynamic De-List Bids are submitted at a price than are needed to clear the market, the bids shall be cleared pro-rata, subject to honoring the Rationing Minimum Limit of the resources. Where an offer or bid may be rationed, such rationing may not result in procuring an amount of capacity that is below the associated resource's Rationing Minimum Limit.

III.13.2.7. Determination of Capacity Clearing Prices.

The Capacity Clearing Price in each Capacity Zone shall be the price established by the descending clock auction as described in Section III.13.2.3, subject to the other provisions of this Section III.13.2.7. The Capacity Clearing Price for the Rest-of-Pool Capacity Zone and the Capacity Clearing Price for each

import-constrained Capacity Zone shall not exceed the Forward Capacity Auction Starting Price. The Capacity Clearing Price for an export-constrained Capacity Zone shall not be less than zero.

III.13.2.7.1. Import-Constrained Capacity Zone Capacity Clearing Price Floor.

The Capacity Clearing Price in an import-constrained Capacity Zone shall not be lower than the Capacity Clearing Price in the Rest-of-Pool Capacity Zone. If after the Forward Capacity Auction is conducted, the Capacity Clearing Price in an import-constrained Capacity Zone is less than the Capacity Clearing Price in the Rest-of-Pool Capacity Zone, all resources clearing in the import-constrained Capacity Zone shall be paid based on the Capacity Clearing Price in the Rest-of-Pool Capacity Zone during the associated Capacity Commitment Period.

III.13.2.7.2. Export-Constrained Capacity Zone Capacity Clearing Price Ceiling.

The Capacity Clearing Price in an export-constrained Capacity Zone shall not be higher than the Capacity Clearing Price in the Rest-of-Pool Capacity Zone.

The Capacity Clearing Price in a nested Capacity Zone shall not be higher than the Capacity Clearing Price in the Capacity Zone within which it is located.

III.13.2.7.3. [Reserved.]

III.13.2.7.3A. Treatment of Imports.

At the Capacity Clearing Price, if the amount of capacity offered from New Import Capacity Resources and Existing Import Capacity Resources over an interface between an external Control Area and the New England Control Area is greater than that interface's approved capacity transfer limit (net of tie benefits, or net of HQICC in the case of the Phase I/II HVDC-TF):

(a) the full amount of capacity offered at that price from Existing Import Capacity Resources associated with contracts listed in Section III.13.1.3.3.A(c) shall clear, unless that amount of capacity is greater than the interface's approved capacity transfer limit (net of tie benefits, or net of HQICC in the case of the Phase I/II HVDC-TF), in which case the capacity offered at that price from Existing Import Capacity Resources associated with contracts listed in Section III.13.1.3.3.A(c) shall be rationed such that the interface's approved capacity transfer limit (net of tie benefits, or net of HQICC in the case of the Phase I/II HVDC-TF) is not exceeded; and

(b) if there is space remaining over the interface after the allocation described in subsection (a) above, then the capacity offered at that price from New Import Capacity Resources and Existing Import Capacity Resources other than Existing Import Capacity Resources associated with the contracts listed in Section III.13.1.3.3.A(c) will be rationed such that the interface's approved capacity transfer limit (net of tie benefits, or net of HQICC in the case of the Phase I/II HVDC-TF) is not exceeded. If the capacity offered at that price by any single New Import Capacity Resource or Existing Import Capacity Resource that is not associated with the contracts listed in Section III.13.1.3.3.A(c) is greater than the interface's approved capacity transfer limit (net of tie benefits, or net of HQICC in the case of the Phase I/II HVDC-TF), then the capacity offered by that resource that is above the interface's approved capacity transfer limit (net of tie benefits, or net of HQICC in the case of the Phase I/II HVDC-TF) shall not be included in the rationing.

III.13.2.7.4. Effect of Capacity Rationing Rule on Capacity Clearing Price.

Where the requirement that offers and bids clear or not clear in whole (Section III.13.2.6) prohibits the descending clock auction in its normal progression from clearing one or more Capacity Zones at the precise amount of capacity determined by the Capacity Zone Demand Curves specified in Section III.13.2.2, then the auctioneer shall analyze the aggregate supply curve to determine cleared capacity offers and Capacity Clearing Prices that seek to maximize social surplus for the associated Capacity Commitment Period. The clearing algorithm may result in offers below the Capacity Clearing Price not clearing, and in de-list bids below the Capacity Clearing Price clearing.

III.13.2.7.5. Effect of Decremental Repowerings on the Capacity Clearing Price.

Where the effect of accounting for certain repowering offers and bids (as described in Section III.13.2.3.2(e)) results in the auction not clearing at the lowest price for the required quantity of capacity, then the auctioneer will conduct additional auction rounds of the Forward Capacity Auction as necessary to minimize capacity costs.

III.13.2.7.6. Minimum Capacity Award.

Each offer (excluding offers from Conditional Qualified New Resources that do not satisfy the conditions specified in Sections III.13.2.5.1(i)-(iii)) clearing in the Forward Capacity Auction shall be awarded a Capacity Supply Obligation at least as great as the amount of capacity offered at the End-of-Round Price in the final round of the Forward Capacity Auction. For Intermittent Power Resources, the Capacity

Supply Obligation for months in the winter period (as described in Section III.13.1.5) shall be adjusted based on its winter Qualified Capacity as determined pursuant to Section III.13.1.1.2.2.6 and Section III.13.1.2.2.2.

III.13.2.7.7. Tie-Breaking Rules.

Where the provisions in this Section III.13.2 for clearing the Forward Capacity Auction (system-wide or in a single Capacity Zone) result in a tie – that is, where two or more resources offer sufficient capacity at prices that would clear the auction at the same minimum costs – the auctioneer shall apply the following rules (in sequence, as necessary) to determine clearing:

(a) [Reserved.]

(b) If multiple projects may be rationed, they will be rationed proportionately.

(c) Where clearing either the offer associated with a resource with a higher queue priority at a Conditional Qualified New Resource's location or the offer associated with the Conditional Qualified New Resource would result in equal costs, the offer associated with the resource with the higher queue priority shall clear.

(d) The offer associated with the Project Sponsor having the lower market share in the capacity auction (including Existing Generating Capacity Resources, Existing Import Capacity Resources, and Existing Demand Capacity Resources) shall be cleared.

III.13.2.8. Capacity Substitution Auctions.

III.13.2.8.1. Administration of Substitution Auctions.

Following the completion of the primary auction-clearing process of the Forward Capacity Auction as provided for in Section III.13.2, the ISO shall conduct a substitution auction, using a static double auction to clear supply offers (offers to assume a Capacity Supply Obligation) and demand bids (bids to shed a Capacity Supply Obligation). Supply offers and demand bids will be modeled in the Capacity Zone where the associated resources are electrically interconnected.

III.13.2.8.1.1. Substitution Auction Clearing and Awards.

The substitution auction shall maximize total social surplus as specified by the demand bids and supply offers used in the auction. The maximization is constrained as follows:

(i) By the external interface limits modeled in the primary auction-clearing process.

(ii) Such that the net cleared Capacity Supply Obligations (total acquired less total shed) in the substitution auction is equal to zero.

(iii) Such that, for each import-constrained Capacity Zone, if the zone's total Capacity Supply Obligations awarded in the primary auction-clearing process of the Forward Capacity Auction is less than the zone threshold quantity specified below, then the zone's net cleared Capacity Supply Obligations (total acquired less total shed) in the substitution auction is equal to zero; otherwise, the sum of the zone's total Capacity Supply Obligations awarded in the primary auction-clearing process and the zone's net cleared Capacity Supply Obligations (total acquired less total shed) in the substitution auction is greater than or equal to the zone threshold quantity specified below.

(iv) Such that, for each export-constrained Capacity Zone, if the zone's total Capacity Supply Obligations awarded in the primary auction-clearing process of the Forward Capacity Auction is greater than the zone threshold quantity specified below, then the zone's net cleared Capacity Supply Obligations (total acquired less total shed) in the substitution auction is equal to zero; otherwise, the sum of the zone's total Capacity Supply Obligations awarded in the primary auction-clearing process and the zone's net cleared Capacity Supply Obligations (total acquired less total shed) in the substitution auction is less than or equal to the zone threshold quantity specified below.

In applying constraint (iii), the zone threshold quantity for an import-constrained Capacity Zone shall be equal to the sum of its Capacity Zone Demand Curve truncation point quantity specified in Section III.13.2.2.2 and the total quantity of any Export Bids and any Administrative Export De-List Bids for which the exporting resource is located outside the import-constrained Capacity Zone, that are used to export capacity across an external interface connected to the import-constrained Capacity Zone, and that cleared in the primary auction-clearing process of the Forward Capacity Auction.

In applying constraint (iv), the zone threshold quantity for an export-constrained Capacity Zone shall be equal to its Capacity Zone Demand Curve truncation point quantity specified in Section III.13.2.2.3 less the total quantity of any Export Bids and any Administrative Export De-List Bids for which the exporting resource is located in the export-constrained Capacity Zone, including any Export Bids and any Administrative Export De-List Bids in an associated nested export-constrained Capacity Zone, that are

used to export capacity across an external interface connected to another Capacity Zone, and that cleared in the primary auction-clearing process of the Forward Capacity Auction.

In applying constraints (iii) and (iv), a zone's total Capacity Supply Obligations awarded in the primary auction-clearing process of the Forward Capacity Auction and net cleared Capacity Supply Obligations (total acquired less total shed) in the substitution auction shall include the Capacity Supply Obligations of Import Capacity Resources at each external interface connected to the Capacity Zone.

In applying constraints (iii) and (iv), a zone's total Capacity Supply Obligations awarded in the primary auction-clearing process of the Forward Capacity Auction shall include the Capacity Supply Obligations awarded to Proxy De-List Bids within the zone, and the zone's net cleared Capacity Supply Obligations (total acquired less total shed) in the substitution auction shall include the Capacity Supply Obligations shed from demand bids associated with Proxy De-List Bids within the zone.

In cases in which there are multiple clearing outcomes that would each maximize the substitution auction's objective, the following tie-breaking rules will apply in the following sequence: (i) non-rationable demand bids associated with Lead Market Participants having the largest total FCA Qualified Capacity of Existing Capacity Resources will be cleared first; and (ii) rationable supply offers will be cleared in proportion to their offer quantity.

For Intermittent Power Resources, other than those participating as the summer resource in a Composite FCM Transaction, the cleared award for supply offers and demand bids shall be adjusted for the months in the winter period (as described in Section III.13.1.5) using the ratio of the resource's cleared offer or bid amount divided by its FCA Qualified Capacity multiplied by its winter Qualified Capacity as determined pursuant to Section III.13.1.1.2.2.6 and Section III.13.1.2.2.2 after removing any portion of the resource's winter Qualified Capacity that is participating in a Composite FCM Transaction.

The cleared offer amount awarded to a Composite FCM Transaction in the substitution auction will be assigned to the summer and winter resources for their respective obligation months during the Capacity Commitment Period as described in Section III.13.1.5.

If, after the substitution auction, a resource has a Capacity Supply Obligation below its Economic Minimum Limit, it must meet the requirements of Section III.13.6.1.1.1.

III.13.2.8.1.2. Substitution Auction Pricing.

The substitution auction will specify clearing prices for Capacity Zones and external interfaces as follows.

For each import-constrained Capacity Zone, if the sum of the zone's total Capacity Supply Obligations awarded in the primary auction-clearing process of the Forward Capacity Auction and the zone's net cleared Capacity Supply Obligations (total acquired less total shed) in the substitution auction is greater than its zone threshold quantity specified in Section III.13.2.8.1.1, then supply offers and demand bids in the substitution auction in the import-constrained Capacity Zone shall be treated as offers and bids in the Rest-of-Pool Capacity Zone for purposes of determining substitution auction clearing prices.

For each export-constrained Capacity Zone,

(i) if the sum of the zone's total Capacity Supply Obligations, including Capacity Supply Obligations in a nested Capacity Zone, awarded in the primary auction-clearing process of the Forward Capacity Auction and the zone's net cleared Capacity Supply Obligations (total acquired less total shed) in the substitution auction including net cleared Capacity Supply Obligations in the nested Capacity Zone is less than its zone threshold quantity specified in Section III.13.2.8.1.1, then supply offers and demand bids in the substitution auction in the export-constrained Capacity Zone (excluding supply offers and demand bids in the nested Capacity Zone that are not treated as offers and bids in the export-constrained Capacity Zone pursuant to Section III.13.2.8.1.2(ii)) shall be treated as offers and bids in the Rest-of-Pool Capacity Zone for purposes of determining substitution auction clearing prices.

(ii) if the sum of a nested Capacity Zone's Capacity Supply Obligations awarded in the primary auction-clearing process of the Forward Capacity Auction and the nested Capacity Zone's net cleared Capacity Supply Obligations (total acquired less total shed) in the substitution auction is less than its zone threshold quantity specified in Section III.13.2.8.1.1, then supply offers and demand bids in the substitution auction in the nested Capacity Zone shall be treated as offers and bids in the export-constrained Capacity Zone within which the nested Capacity Zone is located, for purposes of determining substitution auction clearing prices.

The substitution auction clearing prices for the Rest-of-Pool Capacity Zone and for any constrained zones pooled with the Rest-of-Pool Capacity Zone for pricing purposes shall be determined by the price of the

demand bid or supply offer that is marginal. If a demand bid associated with a Proxy De-List Bid is marginal, then the substitution auction clearing prices shall be set equal to the Capacity Clearing Prices.

The substitution auction clearing price for a constrained Capacity Zone that is not pooled with the Rest-of-Pool Capacity Zone for pricing purposes shall be determined by the price of the demand bid or supply offer associated with the separately-priced constrained Capacity Zone that is marginal. If a demand bid associated with a Proxy De-List Bid is marginal, then the substitution auction clearing price shall be set equal to the Capacity Clearing Price for the constrained Capacity Zone.

The substitution auction clearing price for a nested export-constrained Capacity Zone that is not pooled with the export-constrained Capacity Zone in which it is located for pricing purposes shall be determined by the price of the demand bid or supply offer that is marginal in the nested export-constrained Capacity Zone. If a demand bid associated with a Proxy De-List Bid is marginal, then the substitution auction clearing price for the nested export-constrained Capacity Zone shall be equal to the Capacity Clearing Price for that nested export-constrained Capacity Zone.

If the net quantity of Capacity Supply Obligations awarded in the primary Forward Capacity Auction and substitution auction over an interface between the New England Control Area and an external Control Area is less than that interface's approved capacity transfer limit (net of tie benefits, or net of HQICC in the case of the Phase I/II HVDC-TF), then supply offers and demand bids in the substitution auction at the interface shall be treated as offers and bids in the modeled Capacity Zone associated with that interface for purposes of determining substitution auction clearing prices.

If the net quantity of Capacity Supply Obligations awarded in the primary Forward Capacity Auction and substitution auction over an interface between the New England Control Area and an external Control Area is equal to that interface's approved capacity transfer limit (net of tie benefits, or net of HQICC in the case of the Phase I/II HVDC-TF), then the substitution auction clearing price for that interface will be determined by the demand bid or supply offer that is marginal at that interface. If a cleared demand bid associated with a Proxy De-List Bid is marginal at the external interface, then the substitution auction clearing price for that interface shall be set equal to the Capacity Clearing Price for that interface.

The substitution auction clearing price for an import-constrained Capacity Zone where the total Capacity Supply Obligations awarded in the primary action-clearing process of the Forward Capacity Auction are greater than or equal to the zone's threshold quantity specified in Section III.13.2.8.1.1 shall not be lower

than the substitution auction clearing price for the Rest-of-Pool Capacity Zone.

The substitution auction clearing price for an export-constrained Capacity Zone that is not a nested export-constrained Capacity Zone, where the total Capacity Supply Obligations awarded in the primary auction-clearing process of the Forward Capacity Auction are less than or equal to the zone's threshold quantity specified in Section III.13.2.8.1.1 shall not exceed the substitution auction clearing price for the Rest-of-Pool Capacity Zone.

The substitution auction clearing price for a nested export-constrained Capacity Zone where the total Capacity Supply Obligations awarded in the primary auction-clearing process of the Forward Capacity Auction are less than or equal to the zone's threshold quantity specified in Section III.13.2.8.1.1 shall not exceed the substitution auction clearing price for the Capacity Zone within which it is located.

The substitution auction clearing price at an external interface shall not exceed the substitution auction clearing price in the Capacity Zone connected to the external interface.

If, pursuant to the rules specified above, the substitution auction clearing price for any Capacity Zone or external interface would exceed the Capacity Clearing Price for that location, the substitution auction clearing price for that location only is set equal to its Capacity Clearing Price.

The substitution auction clearing price for any Capacity Zone or external interface cannot be less than negative one multiplied by the Forward Capacity Auction Starting Price.

III.13.2.8.2. Supply Offers in the Substitution Auction.

III.13.2.8.2.1. Supply Offers.

To participate as supply in the substitution auction, a Project Sponsor for a New Capacity Resource must meet the following criteria:

(a) The Project Sponsor and the New Capacity Resource must meet all the requirements for participation in the Forward Capacity Auction specified in Section III.13.1.

(b) The Project Sponsor must elect to have the resource participate in the substitution auction during the New Capacity Show of Interest Window. Pursuant to an election, the resource's total amount of FCA Qualified Capacity that qualifies as a New Capacity Resource will be obligated to

participate in the substitution auction, including any capacity of a Renewable Technology Resource that was not qualified due to proration pursuant to Section III.13.1.1.2.10(a), and subject to the other provisions of this Section III.13.2.8.2.

(c) The Project Sponsor must certify that the New Capacity Resource is a Sponsored Policy Resource as part of the submission of the New Capacity Qualification Package.

Substitution auction supply offers are rationable.

A resource participating in the Forward Capacity Auction as a New Generating Capacity Resource pursuant to Section III.13.1.1.1.2 (resources previously counted as capacity resources) is not eligible to participate as supply in the substitution auction. A resource is not eligible to participate as supply in the substitution auction if it has submitted a demand bid for the substitution auction.

A Composite FCM Transaction comprised of a summer resource that is a Sponsored Policy Resource is eligible to participate as supply in the substitution auction.

A Conditional Qualified New Resource may participate in the substitution auction provided that the resource with which it has overlapping interconnection impacts: (i) did not receive a Capacity Supply Obligation, fully or partially, in the primary auction-clearing process, and: (ii) is not eligible to participate in the substitution auction. A resource having a higher priority in the queue than a Conditional Qualified New Resource with which it has overlapping interconnection impact may participate in the substitution auction provided that the Conditional Qualified New Resource did not receive a Capacity Supply Obligation, fully or partially, in the primary auction-clearing process.

III.13.2.8.2.2. Supply Offer Prices.

Project Sponsors must submit substitution auction supply offer prices no later than five Business Days after the deadline for submission of offers composed of separate resources.

A substitution auction supply offer must be in the form of a curve (with up to five price-quantity pairs). The curve may not decrease in quantity as the price increases. A supply offer price for the substitution auction may not be greater than the Forward Capacity Auction Starting Price or lower than negative one multiplied by the Forward Capacity Auction Starting Price.

If the offer quantity does not equal the resource's FCA Qualified Capacity, the quantity for which no offer price was submitted will be assigned a price equal to the Forward Capacity Auction Starting Price.

III.13.2.8.2.3. Supply Offers Entered into the Substitution Auction

Supply offers for resources that satisfy all of the criteria in Section III.13.2.8.2.1 to participate in the substitution auction may be adjusted prior to conducting the substitution auction-clearing process using the following adjustments:

(a) Any portion of a resource's FCA Qualified Capacity that was cleared (received a Capacity Supply Obligation) in the primary auction-clearing process will be removed from the resource's substitution auction supply offer beginning with the lowest priced price-quantity pairs.

(b) After performing the adjustment specified in Section III.13.2.8.2.3(a), any price-quantity pairs in a resource's substitution auction supply offer with a price greater than the Capacity Clearing Price for the resource's Capacity Zone or external interface are removed from the offer.

III.13.2.8.3. Demand Bids in the Substitution Auction.

III.13.2.8.3.1. Demand Bids.

Market Participants with Existing Generating Capacity Resources or Existing Import Capacity Resources associated with External Elective Transmission Upgrades may elect to submit demand bids for the substitution auction for those resources by the Existing Capacity Retirement Deadline. The election must specify the total amount of the resource's Qualified Capacity that will be associated with its demand bid.

A resource, including any portion of an existing resource that qualifies as a New Capacity Resource, must have achieved FCM Commercial Operation no later than seven days after the issuance by the ISO of the qualification determination notification described in Section III.13.1.2.4(b) in order to participate as demand in the substitution auction.

Regardless of whether an election is made, a demand bid is required for any portion of a resource that is associated with a Retirement De-List Bid, provided that the entire resource has achieved FCM Commercial Operation no later than seven days after the issuance by the ISO of the qualification determination notification described in Section III.13.1.2.4(b).

A resource for which a demand bid election has been made cannot participate in a Composite FCM Transaction, cannot be designated as a Self-Supplied FCA Resource, and will not have incremental summer or winter capacity that does not span the entire Capacity Commitment Period subjected to the treatment specified in Section III.13.1.1.1.3.A.

Demand bids are non-rationable.

A demand bid will be entered into the substitution auction for the portion of the resource that receives a Capacity Supply Obligation in the primary auction-clearing process, subject to the other provisions of this Section III.13.2.8.3. A resource, or portion thereof, associated with a cleared demand bid shall be retired from all New England Markets at the start of the Capacity Commitment Period associated with the Forward Capacity Auction.

III.13.2.8.3.1A Substitution Auction Test Prices.

(a) **Participant-Submitted Test Price.** For auctions associated with a Capacity Commitment Period that begins on or after June 1, 2023, Market Participants that submit a substitution auction demand bid must submit a test price, calculated using the method described below, by the Existing Capacity Retirement Deadline.

The test price for the capacity associated with a resource's demand bid must be calculated using the same methodology as a Retirement De-List Bid, except that a Market Participant may not submit test prices for multiple price-quantity segments but must submit a single test price using, as necessary, aggregated cost and revenue data. The test price must be accompanied by the same documentation required for Retirement De-List Bids above the Dynamic De-List Bid Threshold pursuant to Section III.13.1.2.3.2.1. A Market Participant must submit a test price regardless of whether the price is below the Dynamic De-List Bid Threshold.

A Market Participant is not required to submit a test price for any resource for which the demand bid is less than 3 MW. The applicable test price for any such resource is $0.00/kW-month.

(b) **IMM-Determined Test Price.** The Internal Market Monitor shall review each test price submission using the methodology specified in Section III.13.1.2.3.2.1 for evaluating Retirement De-List Bids, regardless of whether the submitted test price is below the Dynamic De-List Bid Threshold. For purposes of this review, the expected revenues for a cleared substitution auction demand bid shall not be

included as a component of opportunity costs. After due consideration and consultation with the Market Participant, as appropriate, the Internal Market Monitor shall replace the submitted test price with an IMM-determined test price if the submitted test price is not consistent with the sum of the net present value of the resource's expected cash flows plus reasonable expectations about the resource's Capacity Performance Payments plus reasonable opportunity costs.

The Internal Market Monitor's determination regarding a Market Participant-submitted test price shall be included in the retirement determination notification described in Section III.13.1.2.4(a) and in the filing made to the Commission as described in Section III.13.8.1(a).

The test price used for purposes of the substitution auction shall be the Market Participant-submitted test price, as adjusted by the Internal Market Monitor pursuant to this Section III.13.2.8.3.1A(b), and as further adjusted by the Commission in response to the Internal Market Monitor's filing pursuant to Section III.13.1.2.4(a).

III.13.2.8.3.2. Demand Bid Prices.

Market Participants must submit substitution auction demand bid prices no later than five Business Days after the deadline for submission of offers composed of separate resources.

A substitution auction demand bid must be in the form of a curve (with up to five price-quantity pairs). The curve may not decrease in quantity as the price decreases. A demand bid price for the substitution auction may not be greater than the Forward Capacity Auction Starting Price or lower than negative one multiplied by the Forward Capacity Auction Starting Price.

If the bid quantity does not equal the total bid amount submitted by the Market Participant or required for a Retirement De-List Bid pursuant to Section III.13.2.8.3.1, the quantity for which no bid price was specified will be assigned a price equal to negative one multiplied by the Forward Capacity Auction Starting Price.

For auctions associated with a Capacity Commitment Period that begins on or after June 1, 2023, Market Participants may elect either of the demand bid adjustment methods specified in Section III.13.2.8.3.3(b) for the resource by no later than five Business Days after the deadline for submission of offers composed of separate resources. If no such election is made, the adjustment applied shall be the method specified in Section III.13.2.8.3.3(b)(i).

III.13.2.8.3.3. Demand Bids Entered into the Substitution Auction.

If a resource is determined to be needed for reliability pursuant to Section III.13.2.5.2.5, then any demand bid associated with the resource will not be further included in the substitution auction. If a resource is awarded a Capacity Supply Obligation in the primary auction-clearing process and the Capacity Clearing Price is less than ninety percent of the resource's test price as established pursuant to Section III.13.2.8.3.1A, then the resource's demand bid will not be included in the substitution auction.

Demand bids for resources that satisfy all of the criteria in Section III.13.2.8.3.1 to participate in the substitution auction will be adjusted prior to conducting the substitution auction-clearing process using the following adjustments:

(a) For the substitution auction associated with the Capacity Commitment Period beginning on June 1, 2022, any portion of a resource's demand bid that exceeds its Capacity Supply Obligation awarded in the primary auction-clearing process will be removed from the substitution auction demand bid beginning with the highest priced price-quantity pairs.

(b) For substitution auctions associated with a Capacity Commitment Period that begins on or after June 1, 2023, a resource's demand bid will be adjusted using one of the following methods as elected pursuant to Section III.13.2.8.3.2:

(i) The portion of a resource's capacity that did not receive a Capacity Supply Obligation in the primary auction-clearing process will be removed from the substitution auction demand bid beginning with the highest priced price-quantity pair.

(ii) Any portion of a resource's demand bid that exceeds its Capacity Supply Obligation awarded in the primary auction-clearing process will be removed from the substitution auction demand bid beginning with the lowest priced price-quantity pair.

(c) After performing the modification specified in Sections III.13.2.8.3.3(a) or III.13.2.8.3.3(b), any price-quantity pairs in a resource's substitution auction demand bid with a price greater than the Capacity Clearing Price for the resource's Capacity Zone or external interface will have its price reduced to the Capacity Clearing Price for the resource's Capacity Zone or external interface.

Except as provided in Section III.13.2.5.2.1(c), a rationable demand bid will be entered into the substitution auction on behalf of any Proxy De-List Bid associated with a Permanent De-List Bid or

Retirement De-List Bid. The demand bid quantity will equal the portion of the Proxy De-List Bid that was not cleared (received a Capacity Supply Obligation) in the first run of the primary auction-clearing process. The demand bid will have priority to clear before non-rationable demand bids.

SECTION III

MARKET RULE 1

APPENDIX A

MARKET MONITORING,
REPORTING AND MARKET POWER MITIGATION

APPENDIX A

MARKET MONITORING, REPORTING AND MARKET POWER MITIGATION

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MARKET MONITORING, REPORTING AND MARKET POWER MITIGATION

III.A.1. Introduction and Purpose; Structure and Oversight: Independence.

III.A.1.1. Mission Statement.

The mission of the Internal Market Monitor and External Market Monitor shall be (1) to protect both consumers and Market Participants by the identification and reporting of market design flaws and market power abuses; (2) to evaluate existing and proposed market rules, tariff provisions and market design elements to remove or prevent market design flaws and recommend proposed rule and tariff changes to the ISO; (3) to review and report on the performance of the New England Markets; (4) to identify and notify the Commission of instances in which a Market Participant's behavior, or that of the ISO, may require investigation; and (5) to carry out the mitigation functions set forth in this ***Appendix A.***

III.A.1.2. Structure and Oversight.

The market monitoring and mitigation functions contained in this ***Appendix A*** shall be performed by the Internal Market Monitor, which shall report to the ISO Board of Directors and, for administrative purposes only, to the ISO Chief Executive Officer, and by an External Market Monitor selected by and reporting to the ISO Board of Directors. Members of the ISO Board of Directors who also perform management functions for the ISO shall be excluded from oversight and governance of the Internal Market Monitor and External Market Monitor. The ISO shall enter into a contract with the External Market Monitor addressing the roles and responsibilities of the External Market Monitor as detailed in this ***Appendix A***. The ISO shall file its contract with the External Market Monitor with the Commission. In order to facilitate the performance of the External Market Monitor's functions, the External Market Monitor shall have, and the ISO's contract with the External Market Monitor shall provide for, access by the External Market Monitor to ISO data and personnel, including ISO management responsible for market monitoring, operations and billing and settlement functions. Any proposed termination of the contract with the External Market Monitor or modification of, or other limitation on, the External Market Monitor's scope of work shall be subject to prior Commission approval.

III.A.1.3. Data Access and Information Sharing.

The ISO shall provide the Internal Market Monitor and External Market Monitor with access to all market data, resources and personnel sufficient to enable the Internal Market Monitor and External Market Monitor to perform the market monitoring and mitigation functions provided for in this ***Appendix A***.

This access shall include access to any confidential market information that the ISO receives from another independent system operator or regional transmission organization subject to the Commission's jurisdiction, or its market monitor, as part of an investigation to determine (a) if a Market Violation is occurring or has occurred, (b) if market power is being or has been exercised, or (c) if a market design flaw exists. In addition, the Internal Market Monitor and External Market Monitor shall have full access to the ISO's electronically generated information and databases and shall have exclusive control over any data created by the Internal Market Monitor or External Market Monitor. The Internal Market Monitor and External Market Monitor may share any data created by it with the ISO, which shall maintain the confidentiality of such data in accordance with the terms of the ISO New England Information Policy.

III.A.1.4. Interpretation.

In the event that any provision of any ISO New England Filed Document is inconsistent with the provisions of this ***Appendix A***, the provisions of ***Appendix A*** shall control. Notwithstanding the foregoing, Sections III.A.1.2, III.A.2.2 (a)-(c), (e)-(h), Section III.A.2.3 (a)-(g), (i), (n) and Section III.A.17.3 are also part of the Participants Agreement and cannot be modified in either ***Appendix A*** or the Participants Agreement without a corresponding modification at the same time to the same language in the other document.

III.A.1.5. Definitions.

Capitalized terms not defined in this ***Appendix A*** are defined in the definitions section of Section I of the Tariff.

III.A.2. Functions of the Market Monitor.

III.A.2.1. Core Functions of the Internal Market Monitor and External Market Monitor.

The Internal Market Monitor and External Market Monitor will perform the following core functions:

(a) Evaluate existing and proposed market rules, tariff provisions and market design elements, and recommend proposed rule and tariff changes to the ISO, the Commission, Market Participants, public utility commissioners of the six New England states, and to other interested entities, with the understanding that the Internal Market Monitor and External Market Monitor are not to effectuate any proposed market designs (except as specifically provided in Section III.A.2.4.4, Section III.A.9 and Section III.A.10 of this ***Appendix A***). In the event the Internal Market Monitor or External Market Monitor believes broader dissemination could lead to exploitation, it shall limit distribution of its

identifications and recommendations to the ISO and to the Commission, with an explanation of why broader dissemination should be avoided at that time. Nothing in this Section III.A.2.1 (a) shall prohibit or restrict the Internal Market Monitor and External Market Monitor from implementing Commission accepted rule and tariff provisions regarding market monitoring or mitigation functions that, according to the terms of the applicable rule or tariff language, are to be performed by the Internal Market Monitor or External Market Monitor.

(b) Review and report on the performance of the New England Markets to the ISO, the Commission, Market Participants, the public utility commissioners of the six New England states, and to other interested entities.

(c) Identify and notify the Commission's Office of Enforcement of instances in which a Market Participant's behavior, or that of the ISO, may require investigation, including suspected tariff violations, suspected violations of Commission-approved rules and regulations, suspected market manipulation, and inappropriate dispatch that creates substantial concerns regarding unnecessary market inefficiencies.

III.A.2.2. Functions of the External Market Monitor.

To accomplish the functions specified in Section III.A.2.1 of this ***Appendix A***, the External Market Monitor shall perform the following functions:

(a) Review the competitiveness of the New England Markets, the impact that the market rules and/or changes to the market rules will have on the New England Markets and the impact that the ISO's actions have had on the New England Markets. In the event that the External Market Monitor uncovers problems with the New England Markets, the External Market Monitor shall promptly inform the Commission, the Commission's Office of Energy Market Regulation staff, the ISO Board of Directors, the public utility commissions for each of the six New England states, and the Market Participants of its findings in accordance with the procedures outlined in Sections III.A.19 and III.A.20 of this ***Appendix A***, provided that in the case of Market Participants and the public utility commissions, information in such findings shall be redacted as necessary to comply with the ISO New England Information Policy. Notwithstanding the foregoing, in the event the External Market Monitor believes broader dissemination could lead to exploitation, it shall limit distribution of its identifications to the ISO and to the Commission, with an explanation of why broader dissemination should be avoided at that time.

(b) Perform independent evaluations and prepare annual and ad hoc reports on the overall competitiveness and efficiency of the New England Markets or particular aspects of the New England

Markets, including the adequacy of this ***Appendix A***, in accordance with the provisions of Section III.A.17 of this ***Appendix A***.

(c) Conduct evaluations and prepare reports on its own initiative or at the request of others.

(d) Monitor and review the quality and appropriateness of the mitigation conducted by the Internal Market Monitor. In the event that the External Market Monitor discovers problems with the quality or appropriateness of such mitigation, the External Market Monitor shall promptly inform the Commission, the Commission's Office of Energy Market Regulation staff, the ISO Board of Directors, the public utility commissions for each of the six New England states, and the Market Participants of its findings in accordance with the procedures outlined in Sections III.A.19 and/or III.A.20 of this ***Appendix A,*** provided that in the case of Market Participants and the public utility commissions, information in such findings shall be redacted as necessary to comply with the ISO New England Information Policy. Notwithstanding the foregoing, in the event the External Market Monitor believes broader dissemination could lead to exploitation, it shall limit distribution of its identifications to the ISO and to the Commission, with an explanation of why broader dissemination should be avoided at that time.

(e) Prepare recommendations to the ISO Board of Directors and the Market Participants on how to improve the overall competitiveness and efficiency of the New England Markets or particular aspects of the New England Markets, including improvements to this ***Appendix A***.

(f) Recommend actions to the ISO Board of Directors and the Market Participants to increase liquidity and efficient trade between regions and improve the efficiency of the New England Markets.

(g) Review the ISO's filings with the Commission from the standpoint of the effects of any such filing on the competitiveness and efficiency of the New England Markets. The External Market Monitor will have the opportunity to comment on any filings under development by the ISO and may file comments with the Commission when the filings are made by the ISO. The subject of any such comments will be the External Market Monitor's assessment of the effects of any proposed filing on the competitiveness and efficiency of the New England Markets, or the effectiveness of this ***Appendix A***, as appropriate.

(h) Provide information to be directly included in the monthly market updates that are provided at the meetings of the Market Participants.

III.A.2.3. Functions of the Internal Market Monitor.

To accomplish the functions specified in Section III.A.2.1 of this ***Appendix A***, the Internal Market Monitor shall perform the following functions:

(a) Maintain ***Appendix A*** and consider whether ***Appendix A*** requires amendment. Any amendments deemed to be necessary by the Internal Market Monitor shall be undertaken after consultation with Market Participants in accordance with Section 11 of the Participants Agreement.

(b) Perform the day-to-day, real-time review of market behavior in accordance with the provisions of this ***Appendix A***.

(c) Consult with the External Market Monitor, as needed, with respect to implementing and applying the provisions of this ***Appendix A.***

(d) Identify and notify the Commission's Office of Enforcement staff of instances in which a Market Participant's behavior, or that of the ISO, may require investigation, including suspected Tariff violations, suspected violations of Commission-approved rules and regulations, suspected market manipulation, and inappropriate dispatch that creates substantial concerns regarding unnecessary market inefficiencies, in accordance with the procedures outlined in Section III.A.19 of this ***Appendix A.***

(e) Review the competitiveness of the New England Markets, the impact that the market rules and/or changes to the market rules will have on the New England Markets and the impact that ISO's actions have had on the New England Markets. In the event that the Internal Market Monitor uncovers problems with the New England Markets, the Internal Market Monitor shall promptly inform the Commission, the Commission's Office of Energy Market Regulation staff, the ISO Board of Directors, the public utility commissions for each of the six New England states, and the Market Participants of its findings in accordance with the procedures outlined in Sections III.A.19 and III.A.20 of this ***Appendix A***, provided that in the case of Market Participants and the public utility commissions, information in such findings shall be redacted as necessary to comply with the ISO New England Information Policy. Notwithstanding the foregoing, in the event the Internal Market Monitor believes broader dissemination could lead to exploitation, it shall limit distribution of its identifications to the ISO and to the Commission, with an explanation of why broader dissemination should be avoided at that time.

(f) Provide support and information to the ISO Board of Directors and the External Market Monitor consistent with the Internal Market Monitor's functions.

(g) Prepare an annual state of the market report on market trends and the performance of the New England Markets, as well as less extensive quarterly reports, in accordance with the provisions of Section III.A.17 of this ***Appendix A***.

(h) Make one or more of the Internal Market Monitor staff members available for regular conference calls, which may be attended, telephonically or in person, by Commission and state commission staff, by representatives of the ISO, and by Market Participants. The information to be provided in the

Internal Market Monitor conference calls is generally to consist of a review of market data and analyses of the type regularly gathered and prepared by the Internal Market Monitor in the course of its business, subject to appropriate confidentiality restrictions. This function may be performed through making a staff member of the Internal Market Monitor available for the monthly meetings of the Market Participants and inviting Commission staff and the staff of state public utility commissions to those monthly meetings.

(i) Be primarily responsible for interaction with external Control Areas, the Commission, other regulators and Market Participants with respect to the matters addressed in this ***Appendix A***.

(j) Monitor for conduct whether by a single Market Participant or by multiple Market Participants acting in concert, including actions involving more than one Resource, that may cause a material effect on prices or other payments in the New England Markets if exercised from a position of market power, and impose appropriate mitigation measures if such conduct is detected and the other applicable conditions for the imposition of mitigation measures as set forth in this ***Appendix A*** are met. The categories of conduct for which the Internal Market Monitor shall perform monitoring for potential mitigation are:

(i) *Economic withholding*, that is, submitting a Supply Offer for a Resource that is unjustifiably high and violates the economic withholding criteria set forth in Section III.A.5 so that (i) the Resource is not or will not be dispatched or scheduled, or (ii) the bid or offer will set an unjustifiably high market clearing price.

(ii) *Uneconomic production from a Resource*, that is, increasing the output of a Resource to levels that would otherwise be uneconomic, absent an order of the ISO, in order to cause, and obtain benefits from, a transmission constraint.

(iii) *Anti-competitive Increment Offers and Decrement Bids*, which are bidding practices relating to Increment Offers and Decrement Bids that cause Day-Ahead LMPs not to achieve the degree of convergence with Real-Time LMPs that would be expected in a workably competitive market, more fully addressed in Section III.A.11 of this ***Appendix A***.

(iv) *Anti-competitive Demand Bids*, which are addressed in Section III.A.10 of this ***Appendix A.***

(v) Other categories of conduct that have material effects on prices or NCPC payments in the New England Markets. The Internal Market Monitor, in consultation with the External Market Monitor, shall; (i) seek to amend ***Appendix A*** as may be appropriate to include any such conduct that would substantially distort or impair the competitiveness of any of

the New England Markets; and (ii) seek such other authorization to mitigate the effects of such conduct from the Commission as may be appropriate.

(k) Perform such additional monitoring as the Internal Market Monitor deems necessary, including without limitation, monitoring for:

(i) Anti-competitive gaming of Resources;

(ii) Conduct and market outcomes that are inconsistent with competitive markets;

(iii) Flaws in market design or software or in the implementation of rules by the ISO that create inefficient incentives or market outcomes;

(iv) Actions in one market that affect price in another market;

(v) Other aspects of market implementation that prevent competitive market results, the extent to which market rules, including this ***Appendix A***, interfere with efficient market operation, both short-run and long-run; and

(vi) Rules or conduct that creates barriers to entry into a market.

The Internal Market Monitor will include significant results of such monitoring in its reports under Section III.A.17 of this ***Appendix A***. Monitoring under this Section III.A.2.3(k) cannot serve as a basis for mitigation under III.A.11 of this ***Appendix A.*** If the Internal Market Monitor concludes as a result of its monitoring that additional specific monitoring thresholds or mitigation remedies are necessary, it may proceed under Section III.A.20.

(l) Propose to the ISO and Market Participants appropriate mitigation measures or market rule changes for conduct that departs significantly from the conduct that would be expected under competitive market conditions but does not rise to the thresholds specified in Sections III.A.5, III.A.10, or III.A.11. In considering whether to recommend such changes, the Internal Market Monitor shall evaluate whether the conduct has a significant effect on market prices or NCPC payments as specified below. The Internal Market Monitor will not recommend changes if it determines, from information provided by Market Participants (or parties that would be subject to mitigation) or from other information available to the Internal Market Monitor, that the conduct and associated price or NCPC payments under investigation are attributable to legitimate competitive market forces or incentives.

(m) Evaluate physical withholding of Supply Offers in accordance with Section III.A.4 below for referral to the Commission in accordance with ***Appendix B*** of this Market Rule l.

(n) If and when established, participate in a committee of regional market monitors to review issues associated with interregional transactions, including any barriers to efficient trade and competition.

III.A.2.4. Overview of the Internal Market Monitor's Mitigation Functions.

III.A.2.4.1. Purpose.

The mitigation measures set forth in this ***Appendix A*** for mitigation of market power are intended to provide the means for the Internal Market Monitor to mitigate the market effects of any actions or transactions that are without a legitimate business purpose and that are intended to or foreseeably could manipulate market prices, market conditions, or market rules for electric energy or electricity products. Actions or transactions undertaken by a Market Participant that are explicitly contemplated in Market Rule l (such as virtual supply or load bidding) or taken at the direction of the ISO are not in violation of this ***Appendix A***. These mitigation measures are intended to minimize interference with open and competitive markets, and thus to permit to the maximum extent practicable, price levels to be determined by competitive forces under the prevailing market conditions. To that end, the mitigation measures authorize the mitigation of only specific conduct that exceeds well-defined thresholds specified below. When implemented, mitigation measures affecting the LMP or clearing prices in other markets will be applied *ex ante*. Nothing in this ***Appendix A***, including the application of a mitigation measure, shall be deemed to be a limitation of the ISO's authority to evaluate Market Participant behavior for potential sanctions under ***Appendix B*** of this Market Rule 1.

III.A.2.4.2. Conditions for the Imposition of Mitigation.

(a) Imposing Mitigation. To achieve the foregoing purpose and objectives, mitigation measures are imposed pursuant to Sections III.A.5, III.A.10, and III.A.11 below:

(b) Notwithstanding the foregoing or any other provision of this ***Appendix A***, and as more fully described in Section III.B.3.2.6 of ***Appendix B*** to this Market Rule 1, certain economic decisions shall not be deemed a form of withholding or otherwise inconsistent with competitive conduct.

III.A.2.4.3. Applicability.

Mitigation measures may be applied to Supply Offers, Increment Offers, Demand Bids, and Decrement Bids, as well as to the scheduling or operation of a generation unit or transmission facility.

III.A.2.4.4. Mitigation Not Provided for Under This *Appendix A*.

The Internal Market Monitor shall monitor the New England Markets for conduct that it determines constitutes an abuse of market power but does not trigger the thresholds specified below for the imposition of mitigation measures by the Internal Market Monitor. If the Internal Market Monitor identifies any such conduct, and in particular conduct exceeding the thresholds specified in this ***Appendix A***, it may make a filing under §205 of the Federal Power Act ("§205") with the Commission requesting authorization to apply appropriate mitigation measures. Any such filing shall identify the particular conduct the Internal Market Monitor believes warrants mitigation, shall propose a specific mitigation measure for the conduct, and shall set forth the Internal Market Monitor's justification for imposing that mitigation measure.

III.A.2.4.5. Duration of Mitigation.

Any mitigation measure imposed on a specific Market Participant, as specified below, shall expire not later than six months after the occurrence of the conduct giving rise to the measure, or at such earlier time as may be specified by the Internal Market Monitor or as otherwise provided in this ***Appendix A*** or in ***Appendix B*** to this Market Rule 1.

III.A.3. Consultation Prior to Determination of Reference Levels for Physical and Financial Parameters of Resources; Fuel Price Adjustments.

Upon request of a Market Participant or at the initiative of the Internal Market Monitor, the Internal Market Monitor shall consult with a Market Participant with respect to the information and analysis used to determine Reference Levels under Section III.A.7 for that Market Participant. In order for the Internal Market Monitor to revise Reference Levels or treat an offer as not violating applicable conduct tests specified in Section III.A.5.5 for an Operating Day for which the offer is submitted, all cost data and other information, other than automated index-based cost data received by the Internal Market Monitor from third party vendors, cost data and information calculated by the Internal Market Monitor, and cost data and information provided under the provisions of Section III.A.3.1 or Section III.A.3.2, must be submitted by a Market Participant, and all consultations must be completed, no later than 5:00 p.m. of the second business day prior to the Operating Day for which the Reference Level will be effective. Adjustments to fuel prices after this time must be submitted in accordance with the fuel price adjustment provisions in Section III.A.3.4.

III.A.3.1. Consultation Prior to Offer.

If an event occurs within the 24 hour period prior to the Operating Day that a Market Participant, including a Market Participant that is not permitted to submit a fuel price adjustment pursuant to Section III.A.3.4(d) believes will cause the operating cost of a Resource to exceed the level that would violate one of the conduct tests specified in Section III.A.5 of this ***Appendix A***, the Market Participant may contact the Internal Market Monitor to provide an explanation of the increased costs. In order for the information to be considered for the purposes of the Day-Ahead Energy Market, the Market Participant must contact the Internal Market Monitor at least 30 minutes prior to the close of the Day-Ahead Energy Market. In order for the information to be considered for purposes of the first commitment analysis performed following the close of the Re-Offer Period, the Market Participant must contact the Internal Market Monitor at least 30 minutes prior to the close of the Re-Offer Period. Cost information submitted thereafter shall be considered in subsequent commitment and dispatch analyses if received between 8:00 a.m. and 5:00 p.m. and at least one hour prior to the close of the next hourly Supply Offer submittal period. If the Internal Market Monitor determines that there is an increased cost, the Internal Market Monitor will either update the Reference Level or treat an offer as not violating applicable conduct tests specified in Section III.A.5.5 for the Operating Day for which the offer is submitted. Any request and all supporting cost data and other verifiable supporting information must be submitted to the Internal Market Monitor prior to the Market participant's submission of the offer.

If a Market Participant believes that the fuel price determined under Section III.A.7.5(e) should be modified, it may contact the Internal Market Monitor to request a change to the fuel price and provide an explanation of the basis for the change. Any request to change the fuel price determined under Section III.A.7.5(e) must be received between the hours of 8:00 a.m. and 5:00 p.m. on any day.

III.A.3.2. Dual Fuel Resources.

In evaluating bids or offers under this ***Appendix A*** for dual fuel Resources, the Internal Market Monitor shall utilize the fuel type specified in the Supply Offer for the calculation of Reference Levels pursuant to Section III.A.7 below. If a Market Participant specifies a fuel type in the Supply Offer that, at the time the Supply Offer is submitted, is the higher cost fuel available to the Resource, then if the ratio of the higher cost fuel to the lower cost fuel, as calculated in accordance with the formula specified below, is greater than 1.75, the Market Participant must within five Business Days:

(a) provide the Internal Market Monitor with written verification as to the cause for the use of the higher cost fuel.

(b) provide the Internal Market Monitor with evidence that the higher cost fuel was used.

If the Market Participant fails to provide supporting information demonstrating the use of the higher-cost fuel within five Business Days of the Operating Day, then the Reference Level based on the lower cost fuel will be used in place of the Supply Offer for settlement purposes.

For purposes of this Section III.A.3.2, the ratio of the Resource's higher cost fuel to the lower cost fuel is calculated as, for the two primary fuels utilized in the dispatch of the Resource, the maximum fuel index price for the Operating Day divided by the minimum fuel index price for the Operating Day, using the two fuel indices that are utilized in the calculation of the Resource's Reference Levels for the Day-Ahead Energy Market for that Operating Day.

III.A.3.3. Market Participant Access to its Reference Levels.

The Internal Market Monitor will make available to the Market Participant the Reference Levels applicable to that Market Participant's Supply Offers through the MUI. Updated Reference Levels will be made available whenever calculated. The Market Participant shall not modify such Reference Levels in the ISO's or Internal Market Monitor's systems.

III.A.3.4. Fuel Price Adjustments.

(a) A Market Participant may submit a fuel price, to be used in calculating the Reference Levels for a Resource's Supply Offer, whenever the Market Participant's expected price to procure fuel for the Resource will be greater than that used by the Internal Market Monitor in calculating the Reference Levels for the Supply Offer. A fuel price may be submitted for Supply Offers entered in the Day-Ahead Energy Market, the Re-Offer Period, or for a Real-Time Offer Change. A fuel price is subject to the following conditions:

(i) In order for the submitted fuel price to be utilized in calculating the Reference Levels for a Supply Offer, the fuel price must be submitted prior to the applicable Supply Offer deadline,

(ii) The submitted fuel price must reflect the price at which the Market Participant expects to be able to procure fuel to supply energy under the terms of its Supply Offer, exclusive of resource-specific transportation costs. Modifications to Reference Levels based on changes to transportation costs must be addressed through the consultation process specified in Section III.A.3.1.

(iii) The submitted fuel price may be no lower than the lesser of (1) 110% of the fuel price used by the Internal Market Monitor in calculating the Reference Levels for the Resource's Supply Offer

or (2) the fuel price used by the Internal Market Monitor in calculating the Reference Levels for the Resource's Supply Offer plus $2.50/MMbtu.

(b) Within five Business Days following submittal of a fuel price, a Market Participant must provide the Internal Market Monitor with documentation or analysis to support the submitted fuel price, which may include but is not limited to (i) an invoice or purchase confirmation for the fuel utilized or (ii) a quote from a named supplier or (iii) a price from a publicly available trading platform or price reporting agency, demonstrating that the submitted fuel price reflects the cost at which the Market Participant expected to purchase fuel for the operating period covered by the Supply Offer, as of the time that the Supply Offer was submitted, under an arm's length fuel purchase transaction. Any amount to be added to the quote from a named supplier, or to a price from a publicly available trading platform or price reporting agency, must be submitted and approved using the provision for consultations prior to the determination of Reference Levels in Section III.A.3. The submitted fuel price must be consistent with the fuel price reflected on the submitted invoice or purchase confirmation for the fuel utilized, the quote from a named supplier or the price from a publicly available trading platform or price reporting agency, plus any approved adder, or the other documentation or analysis provided to support the submitted fuel price.

(c) If, within a 12 month period, the requirements in sub-section (b) are not met for a Resource and, for the time period for which the fuel price adjustment that does not meet the requirements in sub-section (b) was submitted, (i) the Market Participant was determined to be pivotal according to the pivotal supplier test described in Section III.A.5.2.1or (ii) the Resource was determined to be in a constrained area according to the constrained area test described in Section III.A.5.2.2 or (iii) the Resource satisfied any of the conditions described in Section III.A.5.5.6.1, then a fuel price adjustment pursuant to Section III.A.3.4 shall not be permitted for that Resource for up to six months. The following table specifies the number of months for which a Market Participant will be precluded from using the fuel price adjustment, based on the number of times the requirements in sub-section (b) are not met within the 12 month period. The 12 month period excludes any previous days for which the Market Participant was precluded from using the fuel price adjustment. The period of time for which a Market Participant is precluded from using the fuel price adjustment begins two weeks after the most-recent incident occurs.

Number of Incidents	Months Precluded (starting from most-recent incident)
1	2

2 or more	6

III.A.4. Physical Withholding.

III.A.4.1. Identification of Conduct Inconsistent with Competition.

This section defines thresholds used to identify possible instances of physical withholding. This section does not limit the Internal Market Monitor's ability to refer potential instances of physical withholding to the Commission.

Generally, physical withholding involves not offering to sell or schedule the output of or services provided by a Resource capable of serving the New England Markets when it is economic to do so. Physical withholding may include, but is not limited to:

(a) falsely declaring that a Resource has been forced out of service or otherwise become unavailable,

(b) refusing to make a Supply Offer, or schedules for a Resource when it would be in the economic interest absent market power, of the withholding entity to do so,

(c) operating a Resource in Real-Time to produce an output level that is less than the ISO Dispatch Rate, or

(d) operating a transmission facility in a manner that is not economic, is not justified on the basis of legitimate safety or reliability concerns, and contributes to a binding transmission constraint.

III.A.4.2. Thresholds for Identifying Physical Withholding.

III.A.4.2.1. Initial Thresholds.

Except as specified in subsection III.A.4.2.4 below, the following initial thresholds will be employed by the Internal Market Monitor to identify physical withholding of a Resource:

(a) Withholding that exceeds the lower of 10% or 100 MW of a Resource's capacity;

(b) Withholding that exceeds in the aggregate the lower of 5% or 200 MW of a Market Participant's total capacity for Market Participants with more than one Resource; or

(c) Operating a Resource in Real-Time at an output level that is less than 90% of the ISO's Dispatch Rate for the Resource.

III.A.4.2.2. Adjustment to Generating Capacity.

The amounts of generating capacity considered withheld for purposes of applying the foregoing thresholds shall include unjustified deratings, that is, falsely declaring a Resource derated, and the portions of a Resource's available output that are not offered. The amounts deemed withheld shall not include generating output that is subject to a forced outage or capacity that is out of service for maintenance in accordance with an ISO maintenance schedule, subject to verification by the Internal Market Monitor as may be appropriate that an outage was forced.

III.A.4.2.3. Withholding of Transmission.

A transmission facility shall be deemed physically withheld if it is not operated in accordance with ISO instructions and such failure to conform to ISO instructions causes transmission congestion. A transmission facility shall not be deemed withheld if it is subject to a forced outage or is out of service for maintenance in accordance with an ISO maintenance schedule, subject to verification by the Internal Market Monitor as may be appropriate that an outage was forced.

III.A.4.2.4. Resources in Congestion Areas.

Minimum quantity thresholds shall not be applicable to the identification of physical withholding by a Resource in an area the ISO has determined is congested.

III.A.4.3. Hourly Market Impacts.

Before evaluating possible instances of physical withholding for imposition of sanctions, the Internal Market Monitor shall investigate the reasons for the change in accordance with Section III.A.3. If the physical withholding in question is not explained to the satisfaction of the Internal Market Monitor, the Internal Market Monitor will determine whether the conduct in question causes a price impact in the New England Markets in excess of any of the thresholds specified in Section III.A.5, as appropriate.

III.A.5. Mitigation.

III.A.5.1. Resources with Capacity Supply Obligations.

Only Supply Offers associated with Resources with Capacity Supply Obligations will be evaluated for economic withholding in the Day-Ahead Energy Market. All Supply Offers will be evaluated for economic withholding in the Real-Time Energy Market.

III.A.5.1.1. Resources with Partial Capacity Supply Obligations.

Supply Offers associated with Resources with a Capacity Supply Obligation for less than their full capacity shall be evaluated for economic withholding and mitigation as follows:

(a) all Supply Offer parameters shall be reviewed for economic withholding;

(b) the energy price Supply Offer parameter shall be reviewed for economic withholding up to and including the higher of: (i) the block containing the Resource's Economic Minimum Limit, or; (ii) the highest block that includes any portion of the Capacity Supply Obligation;

(c) if a Resource with a partial Capacity Supply Obligation consists of multiple assets, the offer blocks associated with the Resource that shall be evaluated for mitigation shall be determined by using each asset's Seasonal Claimed Capability value in proportion to the total of the Seasonal Claimed Capabilities for all of the assets that make up the Resource. The Lead Market Participant of a Resource with a partial Capacity Supply Obligation consisting of multiple assets may also propose to the Internal Market Monitor the offer blocks that shall be evaluated for mitigation based on an alternative allocation on a monthly basis. The proposal must be made at least five Business Days prior to the start of the month. A proposal shall be rejected by the Internal Market Monitor if the designation would be inconsistent with competitive behavior

III.A.5.2. Structural Tests.

There are two structural tests that determine which mitigation thresholds are applied to a Supply Offer:

(a) if a supplier is determined to be pivotal according to the pivotal supplier test, then the thresholds in Section III.A.5.5.1 "General Threshold Energy Mitigation" and Section III.A.5.5.4 "General Threshold Commitment Mitigation" apply, and;

(b) if a Resource is determined to be in a constrained area according to the constrained area test, then the thresholds in Section III.A.5.5.2 "Constrained Area Energy Mitigation" and Section III.A.5.5.4 "Constrained Area Commitment Mitigation" apply.

III.A.5.2.1. Pivotal Supplier Test.

The pivotal supplier test examines whether a Market Participant has aggregate energy Supply Offers (up to and including Economic Max) that exceed the supply margin in the Real-Time Energy Market. A Market Participant whose aggregate energy associated with Supply Offers exceeds the supply margin is a pivotal supplier.

The supply margin for an interval is the total energy Supply Offers from available Resources (up to and including Economic Max), less total system load (as adjusted for net interchange with other Control Areas, including Operating Reserve). Resources are considered available for an interval if they can provide energy within the interval. The applicable interval for the current operating plan in the Real-Time Energy Market is any of the hours in the plan. The applicable interval for UDS is the interval for which UDS issues instructions.

The pivotal supplier test shall be run prior to each determination of a new operating plan for the Operating Day, and prior to each execution of the UDS.

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III.A.5.2.2. Constrained Area Test.

A Resource is considered to be within a constrained area if:

(a) for purposes of the Real-Time Energy Market, the Resource is located on the import-constrained side of a binding constraint and there is a sensitivity to the binding constraint such that the UDS used to relieve transmission constraints would commit or dispatch the Resource in order to relieve that binding transmission constraint, or;

(b) for purposes of the Day-Ahead Energy Market, the LMP at the Resource's Node exceeds the LMP at the Hub by more than $25/MWh.

III.A.5.3. Calculation of Impact Test in the Day-Ahead Energy Market.

The price impact for the purposes of Section III.A.5.5.2 "Constrained Area Energy Mitigation" is equal to the difference between the LMP at the Resource's Node and the LMP at the Hub.

III.A.5.4. Calculation of Impact Tests in the Real-Time Energy Market.

The energy price impact test applied in the Real-Time Energy Market shall compare two LMPs at the Resource's Node. The first LMP will be calculated based on the Supply Offers submitted for all Resources. If a Supply Offer has been mitigated in a prior interval, the calculation of the first LMP shall be based on the mitigated value. The second LMP shall be calculated substituting Reference Levels for

Supply Offers that have failed the applicable conduct test. The difference between the two LMPs is the price impact of the conduct violation.

A Supply Offer shall be determined to have no price impact if the offer block that violates the conduct test is:

(a) less than the LMP calculated using the submitted Supply Offers, and less than the LMP calculated using Reference Levels for Supply Offers that have failed the conduct test, or;
(b) greater than the LMP calculated using the submitted Supply Offers, and greater than the LMP calculated using Reference Levels for Supply Offers that have failed the conduct test, and the Resource has not been dispatched into the offer block that exceeds the LMP.

III.A.5.5. Mitigation by Type.

III.A.5.5.1. General Threshold Energy Mitigation.

III.A.5.5.1.1. Applicability.

Mitigation pursuant to this section shall be applied to all Supply Offers in the Real-Time Energy Market submitted by a Lead Market Participant that is determined to be a pivotal supplier in the Real-Time Energy Market.

III.A.5.5.1.2. Conduct Test.

A Supply Offer fails the conduct test for general threshold energy mitigation if any offer block price exceeds the Reference Level by an amount greater than 300% or $100/MWh, whichever is lower. Offer block prices below $25/MWh are not subject to the conduct test.

III.A.5.5.1.3. Impact Test.

A Supply Offer that fails the conduct test for general threshold energy mitigation shall be evaluated against the impact test for general threshold energy mitigation. A Supply Offer fails the impact test for general threshold energy mitigation if there is an increase in the LMP greater than 200% or $100/MWh, whichever is lower as determined by the real-time impact test.

III.A.5.5.1.4. Consequence of Failing Both Conduct and Impact Test.

If a Supply Offer fails the general threshold conduct and impact tests, then the financial parameters of the Supply Offer shall be set to their Reference Levels, including all energy offer block prices and all types of Start-Up Fees and the No-Load Fee.

III.A.5.5.2. Constrained Area Energy Mitigation.

III.A.5.5.2.1. Applicability.

Mitigation pursuant to this section shall be applied to Supply Offers in the Day-Ahead Energy Market and Real-Time Energy Market associated with a Resource determined to be within a constrained area.

III.A.5.5.2.2. Conduct Test.

A Supply Offer fails the conduct test for constrained area energy mitigation if any offer block price exceeds the Reference Level by an amount greater than 50% or $25/MWh, whichever is lower.

III.A.5.5.2.3. Impact Test.

A Supply Offer fails the impact test for constrained area energy mitigation if there is an increase greater than 50% or $25/MWh, whichever is lower, in the LMP as determined by the day-ahead or real-time impact test.

III.A.5.5.2.4. Consequence of Failing Both Conduct and Impact Test.

If a Supply Offer fails the constrained area conduct and impact tests, then the financial parameters of the Supply Offer shall be set to their Reference Levels, including all energy offer blocks and all types of Start-Up Fees and the No-Load Fee.

III.A.5.5.3. Manual Dispatch Energy Mitigation.

III.A.5.5.3.1. Applicability.

Mitigation pursuant to this section shall be applied to Supply Offers associated with a Resource, when the Resource is manually dispatched above the Economic Minimum Limit value specified in the Resource's Supply Offer and the energy price parameter of its Supply Offer at the Desired Dispatch Point is greater than the Real-Time Price at the Resource's Node.

III.A.5.5.3.2. Conduct Test.

A Supply Offer fails the conduct test for manual dispatch energy mitigation if any offer block price divided by the Reference Level is greater than 1.10.

III.A.5.5.3.3. Consequence of Failing the Conduct Test.

If a Supply Offer for a Resource fails the manual dispatch energy conduct test, then the financial parameters of the Supply Offer shall be set to their Reference Levels, including all energy offer blocks and all types of Start-Up Fees and the No-Load Fee.

III.A.5.5.4. General Threshold Commitment Mitigation.

III.A.5.5.4.1. Applicability.

Mitigation pursuant to this section shall be applied to all Supply Offers in the Real-Time Energy Market submitted by a Lead Market Participant that is determined to be a pivotal supplier in the Real-Time Energy Market.

III.A.5.5.4.2. Conduct Test.

A Resource shall fail the conduct test for general threshold commitment mitigation if the low Load Cost at Offer divided by the Low Load Cost at Reference Level is greater than 3.00.

III.A.5.5.4.3. Consequence of Failing Conduct Test.

If a Resource fails the general threshold commitment conduct test, then all financial parameters of its Supply Offer are set to their Reference Levels.

III.A.5.5.5. Constrained Area Commitment Mitigation.

III.A.5.5.5.1. Applicability.

Mitigation pursuant to this section shall be applied to any Resource determined to be within a constrained area in the Real-Time Energy Market.

III.A.5.5.5.2. Conduct Test.

A Resource shall fail the conduct test for constrained area commitment mitigation if the Low Load Cost at Offer divided by the Low Load Cost at Reference Level is greater than 1.25.

III.A.5.5.5.3. Consequence of Failing Test.

If a Supply Offer fails the constrained area commitment conduct test, then all financial parameters of its Supply Offer are set to their Reference Levels.

III.A.5.5.6. Reliability Commitment Mitigation.

III.A.5.5.6.1. Applicability.

Mitigation pursuant to this section shall be applied to Supply Offers for Resources that are (a) committed to provide, or Resources that are required to remain online to provide, one or more of the following:

i. local first contingency;
ii. local second contingency;
iii. VAR or voltage;
iv. distribution (Special Constraint Resource Service);
v. dual fuel resource auditing;

(b) otherwise manually committed by the ISO for reasons other than meeting anticipated load plus reserve requirements.

III.A.5.5.6.2. Conduct Test.

A Supply Offer shall fail the conduct test for local reliability commitment mitigation if the Low Load Cost at Offer divided by the Low Load Cost at Reference Level is greater than 1.10.

III.A.5.5.6.3. Consequence of Failing Test.

If a Supply Offer fails the local reliability commitment conduct test, it shall be evaluated for commitment based on an offer with all financial parameters set to their Reference Levels. This includes all offer blocks and all types of Start-Up Fees and the No-Load Fee. If a Resource is committed, then all financial parameters of its Supply Offer are set to their Reference Level.

III.A.5.5.7. Start-Up Fee and No-Load Fee Mitigation.

III.A.5.5.7.1. Applicability.

Mitigation pursuant to this section shall be applied to any Supply Offer submitted in the Day-Ahead Energy Market or Real-Time Energy Market if the resource is committed.

III.A.5.5.7.2. Conduct Test.

A Supply Offer shall fail the conduct test for Start-Up Fee and No-Load Fee mitigation if its Start-Up Fee or No-Load Fee divided by the Reference Level for that fee is greater than 3.

III.A.5.5.7.3. Consequence of Failing Conduct Test.

If a Supply Offer fails the conduct test, then all financial parameters of its Supply Offer shall be set to their Reference Levels.

III.A.5.5.8. Low Load Cost.

Low Load Cost, which is the cost of operating the Resource at its Economic Minimum Limit, is calculated as the sum of:

(a) If the Resource is starting from an offline state, the Start-Up Fee;

(b) The sum of the No Load Fees for the Commitment Period; and

(c) The sum of the hourly values resulting from the multiplication of the price of energy at the Resource's Economic Minimum Limit times its Economic Minimum Limit, for each hour of the Commitment Period.

All Supply Offer parameter values used in calculating the Low Load Cost are the values in place at the time the commitment decision is made.

Low Load Cost at Offer equals the Low Load Cost calculated with financial parameters of the Supply Offer as submitted by the Lead Market Participant.

Low Load Cost at Reference Level equals the Low Load Cost calculated with the financial parameters of the Supply Offer set to Reference Levels.

For Low Load Cost at Offer, the price of energy is the energy price parameter of the Resource's Supply Offer at the Economic Minimum Limit offer block. For Low Load Cost at Reference Level, the price of energy is the energy price parameter of the Resource's Reference Level at the Economic Minimum Limit offer block.

III.A.5.6. Duration of Energy Threshold Mitigation.

Any mitigation imposed pursuant to Sections III.A.5.5.1 “General Threshold Energy Mitigation” or III.A.5.5.2 “Constrained Area Energy Mitigation” is in effect for the following duration:

(a) in the Real-Time Energy Market, mitigation starts when the impact test violation occurs and remains in effect until there is one complete hour in which:

    i. for general threshold mitigation, the Market Participant whose Supply Offer is subject to mitigation is not a pivotal supplier; or,

    ii. for constrained area energy mitigation, the Resource is not located within a constrained area.

(b) in the Day-Ahead Energy Market (applicable only for Section III.A.5.5.2 “Constrained Area Energy Mitigation”), mitigation is in effect in each hour in which the impact test is violated.

Any mitigation imposed pursuant to Section III.A.5.5.3 “Manual Dispatch Energy Mitigation” is in effect for at least one hour until the earlier of either (a) the hour when manual dispatch is no longer in effect and the Resource returns to its Economic Minimum Limit, or (b) the hour when the energy price parameter of its Supply Offer at the Desired Dispatch Point is no longer greater than the Real-Time Price at the Resource’s Node.

III.A.5.7. Duration of Commitment Mitigation.

Any mitigation imposed pursuant to Sections III.A.5.5.4 “General Threshold Commitment Mitigation”, III.A.5.5.5 “Constrained Area Commitment Mitigation”, or III.A.5.5.6 “Reliability Commitment Mitigation” is in effect for the duration of the Commitment Period.

III.A.5.8. Duration of Start-Up Fee and No-Load Fee Mitigation.

Any mitigation imposed pursuant to Sections III.A.5.5.7 “Start-Up Fee and No-Load Fee Mitigation” is in effect for any hour in which the Supply Offer fails the conduct test in Section III.A.5.5.7.2.

III.A.5.9. Correction of Mitigation.

If the Internal Market Monitor determines that there are one or more errors in the mitigation applied in an Operating Day due to data entry, system or software errors by the ISO or the Internal Market Monitor, the Internal Market Monitor shall notify the market monitoring contacts specified by the Lead Market Participant within five Business Days of the applicable Operating Day. The ISO shall correct the error as

part of the Data Reconciliation Process by applying the correct values to the relevant Supply Offer in the settlement process.

The permissibility of correction of errors in mitigation, and the timeframes and procedures for permitted corrections, are addressed solely in this section and not in those sections of Market Rule 1 relating to settlement and billing processes.

III.A.5.10. Delay of Day-Ahead Energy Market Due to Mitigation Process.

The posting of the Day-Ahead Energy Market results may be delayed if necessary for the completion of mitigation procedures.

III.A.6. Physical and Financial Parameter Offer Thresholds.

Physical parameters of a Supply Offer are limited to thresholds specified in this section. Physical parameters are limited by the software accepting offers, except those that can be re-declared in real time during the Operating Day. Parameters that exceed the thresholds specified here but are not limited through the software accepting offers are subject to Internal Market Monitor review after the Operating Day and possible referral to the Commission under Section III.A.19 of this Appendix.

III.A.6.1. Time-Based Offer Parameters.

Supply Offer parameters that are expressed in time (i.e., Minimum Run Time, Minimum Down Time, Start-Up Time, and Notification Time) shall have a threshold of two hours for an individual parameter or six hours for the combination of the time-based offer parameters compared to the Resource's Reference Levels. Offers may not exceed these thresholds in a manner that reduce the flexibility of the Resource. To determine if the six hour threshold is exceeded, all time-based offer parameters will be summed for each start-up state (hot, intermediate and cold). If the sum of the time-based offer parameters for a start-up state exceeds six hours above the sum of the Reference Levels for those offer parameters, then the six hour threshold is exceeded.

III.A.6.2. Financial Offer Parameters.

The Start-Up Fee and the No-Load Fee values of a Resource's Supply Offer may be no greater than three times the Start-Up Fee and No-Load Fee Reference Level values for the Resource. In the event a fuel price has been submitted under Section III.A.3.4, the Start-Up Fee and No-Load Fee for the associated Supply Offer shall be limited in a Real-Time Offer Change. The limit shall be the percent increase in the new fuel price, relative to the fuel price otherwise used by the Internal Market Monitor, multiplied by the

Start-Up Fee or No-Load Fee from the Re-Offer Period. Absent a fuel price adjustment, a Start-Up Fee or No-Load Fee may be changed in a Real-Time Offer Change to no more than the Start-Up Fee and No-Load Fee values submitted for the Re-Offer Period.

III.A.6.3. Other Offer Parameters.

Non-financial or non-time-based offer parameters shall have a threshold of a 100% increase, or greater, for parameters that are minimum values, or a 50% decrease, or greater, for parameters that are maximum values (including, but not limited to, ramp rates, Economic Maximum Limits and maximum starts per day) compared to the Resource's Reference Levels.

Offer parameters that are limited by performance caps or audit values imposed by the ISO are not subject to the provisions of this section.

III.A.7. Calculation of Resource Reference Levels for Physical Parameters and Financial Parameters of Resources.

Market Participants are responsible for providing the Internal Market Monitor with all the information and data necessary for the Internal Market Monitor to calculate up-to-date Reference Levels for each of a Market Participant's Resources.

III.A.7.1. Methods for Determining Reference Levels for Physical Parameters.

The Internal Market Monitor will calculate a Reference Level for each element of a bid or offer that is expressed in units other than dollars (such as time-based or quantity level bid or offer parameters) on the basis of one or more of the following:

(a) Original equipment manufacturer (OEM) operating recommendations and performance data for all Resource types in the New England Control Area, grouped by unit classes, physical parameters and fuel types.

(b) Applicable environmental operating permit information currently on file with the issuing environmental regulatory body.

(c) Verifiable Resource physical operating characteristic data, including but not limited to facility and/or Resource operating guides and procedures, historical operating data and any verifiable documentation related to the Resource, which will be reviewed in consultation with the Market Participant.

III.A.7.2. Methods for Determining Reference Levels for Financial Parameters of Offers.

The Reference Levels for Start-Up Fees, No-Load Fees, Interruption Costs and offer blocks will be calculated separately and assuming no costs from one component are included in another component.

III.A.7.2.1. Order of Reference Level Calculation.

The Internal Market Monitor will calculate a Reference Level for each offer block of an offer according to the following hierarchy, under which the first method that can be calculated is used:

(a) accepted offer-based Reference Levels pursuant to Section III.A.7.3;
(b) LMP-based Reference Levels pursuant to Section III.A.7.4; and,
(c) cost-based Reference Levels pursuant to Section III.A.7.5.

III.A.7.2.2. Circumstances in Which Cost-Based Reference Levels Supersede the Hierarchy of Reference Level Calculation.

In the following circumstances, cost-based Reference Levels shall be used notwithstanding the hierarchy specified in Section III.A.7.2.1.

(a) When in any hour the cost-based Reference Level is higher than either the accepted offer-based or LMP-based Reference Level.
(b) When the Supply Offer parameter is a Start-Up Fee or the No-Load Fee.
(c) For any Operating Day for which the Lead Market Participant requests the cost-based Reference Level.
(d) For any Operating Day for which, during the previous 90 days:
    (i) the Resource has been flagged for VAR, SCR, or as a Local Second Contingency Protection Resource for any hour in the Day-Ahead Energy Market or the Real-Time Energy Market, and;
    (ii) the ratio of the sum of the operating hours for days for which the Resource has been flagged during the previous 90 days in which the number of hours operated out of economic merit order in the Day-Ahead Energy Market and the Real-Time Energy Market exceed the number of hours operated in economic merit order in the Day-Ahead Energy Market and Real-Time Energy Market, to the total number of operating hours in the Day-Ahead Energy Market and Real-Time Energy Market during the previous 90 days is greater than or equal to 50 percent.
(e) When in any hour the incremental energy parameter of an offer, including adjusted offers pursuant to Section III.2.4, is greater than $1,000/MWh.

For the purposes of this subsection:

i. A flagged day is any day in which the Resource has been flagged for VAR, SCR, or as a Local Second Contingency Protection Resource for any hour in either the Day-Ahead Energy Market or the Real-Time Energy Market.

ii. Operating hours are the hours in the Day-Ahead Energy Market for which a Resource has cleared output (MW) greater than zero and hours in the Real-Time Energy Market for which a Resource has metered output (MW) greater than zero. For days for which Real-time Energy Market metered values are not yet available in the ISO's or the Internal Market Monitor's systems, telemetered values will be used.

iii. Self-scheduled hours will be excluded from all of the calculations described in this subsection, including the determination of operating hours.

iv. The determination as to whether a Resource operated in economic merit order during an hour will be based on the energy offer block within which the Resource is operating.

(e) The Market Participant submits a fuel price pursuant to Section III.A.3.4. When the Market Participant submits a fuel price for any hour of a Supply Offer in the Day-Ahead Energy Market or Re-Offer Period, then the cost-based Reference Level is used for the entire Operating Day. If a fuel price is submitted for a Supply Offer after the close of the Re-Offer Period for the next Operating Day or for the current Operating Day, then the cost-based Reference Level for the Supply Offer is used from the time of the submittal to the end of the Operating Day.

(f) When the Market Participant submits a change to any of the following parameters of the Supply Offer after the close of the Re-Offer Period:

(i) hot, intermediate, or cold Start-Up Fee, or a corresponding fuel blend,

(ii) No-Load Fee or its corresponding fuel blends,

(iii) whether to include the Start-Up Fee and No-Load Fee in the Supply Offer,

(iv) the quantity or price value of any Block in the Supply Offer or its corresponding fuel blends, and

(v) whether to use the offer slope for the Supply Offer,

then, the cost-based Reference Level for the Supply Offer will be used from the time of the submittal to the end of the Operating Day.

III.A.7.3. Accepted Offer-Based Reference Level.

The Internal Market Monitor shall calculate the accepted offer-based Reference Level as the lower of the mean or the median of a generating Resource's Supply Offers that have been accepted and are part of the seller's Day-Ahead Generation Obligation or Real-Time Generation Obligation in competitive periods over the previous 90 days, adjusted for changes in fuel prices utilizing fuel indices generally applicable for the location and type of Resource. For purposes of this section, a competitive period is an Operating Day in which the Resource is scheduled in economic merit order.

III.A.7.4. LMP-Based Reference Level.

The Internal Market Monitor shall calculate the LMP-based Reference Level as the mean of the LMP at the Resource's Node during the lowest-priced 25% of the hours that the Resource was dispatched over the previous 90 days for similar hours (on-peak or off-peak), adjusted for changes in fuel prices.

III.A.7.5. Cost-Based Reference Level.

The Internal Market Monitor shall calculate cost-based Reference Levels taking into account information on costs provided by the Market Participant though the consultation process prescribed in Section III.A.3.

The following criteria shall be applied to estimates of cost:

(a) The provision of cost estimates by a Market Participant shall conform with the timing and requirements of Section III.A.3 "Consultation Prior to Determination of Reference Levels for Physical and Financial Parameters of Resources".

(b) Costs must be documented.

(c) All cost estimates shall be based on estimates of current market prices or replacement costs and not inventory costs wherever possible. All cost estimates, including opportunity cost estimates, must be quantified and analytically supported.

(d) When market prices or replacement costs are unavailable, cost estimates shall identify whether the reported costs are the result of a product or service provided by an Affiliate of the Market Participant.

(e) The Internal Market Monitor will evaluate cost information provided by the Market Participant in comparison to other information available to the Internal Market Monitor. Reference Levels associated with Resources for which a fuel price has been submitted under Section III.A.3.4 shall be calculated using the lower of the submitted fuel price or a price, calculated by the Internal Market Monitor, that takes account of the following factors and conditions:

i. Fuel market conditions, including the current spread between bids and asks for current fuel delivery, fuel trading volumes, near-term price quotes for fuel, expected natural gas heating demand, and Market Participant-reported quotes for trading and fuel costs; and

ii. Fuel delivery conditions, including current and forecasted fuel delivery constraints and current line pack levels for natural gas pipelines.

III.A.7.5.1. Estimation of Incremental Operating Cost.

The Internal Market Monitor's determination of a Resource's marginal costs shall include an assessment of the Resource's incremental operating costs in accordance with the following formulas,

Incremental Energy/Reduction:
(incremental heat rate * fuel costs) + (emissions rate * emissions allowance price) + variable operating and maintenance costs + opportunity costs.

Opportunity costs may include, but are not limited to, economic costs associated with complying with:

(a) emissions limits;
(b) water storage limits;
(c) other operating permits that limit production of energy; and
(d) reducing electricity consumption.

No-Load:
(no-load fuel use * fuel costs) + (no-load emissions * emission allowance price)
+ no-load variable operating and maintenance costs + other no-load costs that are not fuel, emissions or variable and maintenance costs.

Start-Up/Interruption:
(start-up fuel use * fuel costs) + (start-up emissions * emission allowance price) + start-up variable and maintenance costs + other start-up costs that are not fuel, emissions or variable and maintenance costs.

III.A.8. [Reserved.]

III.A.9. Regulation.

The Internal Market Monitor will monitor the Regulation market for conduct that it determines constitutes an abuse of market power. If the Internal Market Monitor identifies any such conduct, it may make a filing under Section 205 of the Federal Power Act with the Commission requesting authorization to apply appropriate mitigation measures or to revise Market Rule 1 to address such conduct (or both). The Internal Market Monitor may make such a filing at any time it deems necessary, and may request expedited treatment from the Commission. Any such filing shall identify the particular conduct the Internal Market Monitor believes warrants mitigation or revisions to Market Rule 1 (or both), shall propose a specific mitigation measure for the conduct or revision to Market Rule 1 (or both), and shall set forth the Internal Market Monitor's justification for imposing that mitigation measure or revision to Market Rule 1 (or both).

III.A.10. Demand Bids.

The Internal Market Monitor will monitor the Energy Market as outlined below:

(a) LMPs in the Day-Ahead Energy Market and Real-Time Energy Market shall be monitored to determine whether there is a persistent hourly deviation in any location that would not be expected in a workably competitive market.

(b) The Internal Market Monitor shall compute the average hourly deviation between Day-Ahead Energy Market and Real-Time Energy Market LMPs, measured as: $(LMP_{\text{real time}} / LMP_{\text{day ahead}}) - 1$. The average hourly deviation shall be computed over a rolling four-week period or such other period determined by the Internal Market Monitor.

(c) The Internal Market Monitor shall estimate and monitor the average percentage of each Market Participant's bid to serve load scheduled in the Day-Ahead Energy Market, using a methodology intended to identify a sustained pattern of under-bidding as accurately as deemed practicable. The average percentage will be computed over a specified time period determined by the Internal Market Monitor.

If the Internal Market Monitor determines that: (i) The average hourly deviation is greater than ten percent (10%) or less than negative ten percent (-10%), (ii) one or more Market Participants on behalf of one or more LSEs have been purchasing a substantial portion of their loads with purchases in the Real-Time Energy Market, (iii) this practice has contributed to an unwarranted divergence of LMPs between

the two markets, and (iv) this practice has created operational problems, the Internal Market Monitor may make a filing under Section 205 of the Federal Power Act with the Commission requesting authorization to apply appropriate mitigation measures or to revise Market Rule 1 to address such conduct (or both). The thresholds identified above shall not limit the Internal Market Monitor's authority to make such a filing. The Internal Market Monitor may make such a filing at any time it deems necessary, and may request expedited treatment from the Commission. Any such filing shall identify the particular conduct that the Internal Market Monitor believes warrants mitigation or revisions to Market Rule 1 (or both), shall propose a specific mitigation measure for the conduct or revision to Market Rule 1 (or both), and shall set forth the Internal Market Monitor's justification for imposing that mitigation measure or revision to Market Rule 1 (or both).

III.A.11. Mitigation of Increment Offers and Decrement Bids.

III.A.11.1. Purpose.

The provisions of this section specify the market monitoring and mitigation measures applicable to Increment Offers and Decrement Bids. An Increment Offer is one to supply energy and a Decrement Bid is one to purchase energy, in either such case not being backed by physical load or generation and submitted in the Day-Ahead Energy Market in accordance with the procedures and requirements specified in Market Rule 1 and the ISO New England Manuals.

III.A.11.2. Implementation.

III.A.11.2.1. Monitoring of Increment Offers and Decrement Bids.

Day-Ahead LMPs and Real-Time LMPs in each Load Zone or Node, as applicable, shall be monitored to determine whether there is a persistent hourly deviation in the LMPs that would not be expected in a workably competitive market. The Internal Market Monitor shall compute the average hourly deviation between Day-Ahead LMPs and Real-Time LMPs, measured as:

$(LMP_{\text{real time}} / LMP_{\text{day ahead}}) - 1.$

The average hourly deviation shall be computed over a rolling four-week period or such other period determined by the Internal Market Monitor to be appropriate to achieve the purpose of this mitigation measure.

III.A.11.3. Mitigation Measures.

If the Internal Market Monitor determines that (i) the average hourly deviation computed over a rolling four week period is greater than ten percent (10%) or less than negative ten percent (-10%), and (ii) the bid and offer practices of one or more Market Participants has contributed to a divergence between LMPs in the Day-Ahead Energy Market and Real-Time Energy Market, then the following mitigation measure may be imposed:

The Internal Market Monitor may limit the hourly quantities of Increment Offers for supply or Decrement Bids for load that may be offered in a Location by a Market Participant, subject to the following provisions:

(i) The Internal Market Monitor shall, when practicable, request explanations of the relevant bid and offer practices from any Market Participant submitting such bids.

(ii) Prior to imposing a mitigation measure, the Internal Market Monitor shall notify the affected Market Participant of the limitation.

(iii) The Internal Market Monitor, with the assistance of the ISO, will restrict the Market Participant for a period of six months from submitting any virtual transactions at the same Node(s), and/or electrically similar Nodes to, the Nodes where it had submitted the virtual transactions that contributed to the unwarranted divergence between the LMPs in the Day-Ahead Energy Market and Real-Time Energy Market.

III.A.11.4. Monitoring and Analysis of Market Design and Rules.

The Internal Market Monitor shall monitor and assess the impact of Increment Offers and Decrement Bids on the competitive structure and performance, and the economic efficiency of the New England Markets. Such monitoring and assessment shall include the effects, if any, on such bids and offers of any mitigation measures specified in this Market Rule 1.

III.A.12. Cap on FTR Revenues.

If a holder of an FTR between specified delivery and receipt Locations (i) had an Increment Offer and/or Decrement Bid that was accepted by the ISO for an applicable hour in the Day-Ahead Energy Market for delivery or receipt at or near delivery or receipt Locations of the FTR; and (ii) the result of the acceptance of such Increment Offer or Decrement Bid is that the difference in LMP in the Day-Ahead Energy Market between such delivery and receipt Locations is greater than the difference in LMP between such delivery and receipt Locations in the Real-Time Energy Market, then the Market Participant shall not receive any Transmission Congestion Credit associated with such FTR in such hour, in excess of one divided by the

number of hours in the applicable month multiplied by the amount originally paid for the FTR in the FTR Auction. A Location shall be considered at or near the FTR delivery or receipt Location if seventy-five % or more of the energy injected or withdrawn at that Location and which is withdrawn or injected at another Location is reflected in the constrained path between the subject FTR delivery and receipt Locations that were acquired in the FTR Auction.

III.A.13. Additional Internal Market Monitor Functions Specified in Tariff.

III.A.13.1. Review of Offers and Bids in the Forward Capacity Market.

In accordance with the following provisions of Section III.13 of Market Rule 1, the Internal Market Monitor is responsible for reviewing certain bids and offers made in the Forward Capacity Market. Section III.13 of Market Rule 1 specifies the nature and detail of the Internal Market Monitor's review and the consequences that will result from the Internal Market Monitor's determination following such review.

(a) [Reserved].

(b) Section III.13.1.2.3.1.6.3 - Internal Market Monitor review of Static De-List Bids, Permanent De-List Bids, and Retirement De-List Bids from an Existing Generating Capacity Resource that is associated with a Station having Common Costs.

(c) Section III.13.1.2.3.2 - Review by Internal Market Monitor of Bids from Existing Generating Capacity Resources.

(d) Section III.13.1.3.3A(d) - Review by Internal Market Monitor of offers from Existing Import Capacity Resources.

(e) Section III.13.1.3.5.6 - Review by Internal Market Monitor of Offers from New Import Capacity Resources.

(f) Section III.13.1.7 - Internal Market Monitor review of summer and winter Seasonal Claimed Capability values.

III.A.13.2. Supply Offers and Demand Bids Submitted for Reconfiguration Auctions in the Forward Capacity Market.

Section III.13.4 of Market Rule 1 addresses reconfiguration auctions in the Forward Capacity Market. As addressed in Section III.13.4.2 of Market Rule 1, a supply offer or demand bid submitted for a reconfiguration auction shall not be subject to mitigation by the Internal Market Monitor.

III.A.13.3. Monitoring of Transmission Facility Outage Scheduling.

Appendix G of Market Rule 1 addresses the scheduling of outages for transmission facilities. The Internal Market Monitor shall monitor the outage scheduling activities of the Transmission Owners. The Internal Market Monitor shall have the right to request that each Transmission Owner provide information to the Internal Market Monitor concerning the Transmission Owner's scheduling of transmission facility outages, including the repositioning or cancellation of any interim approved or approved outage, and the Transmission Owner shall provide such information to the Internal Market Monitor in accordance with the ISO New England Information Policy.

III.A.13.4. Monitoring of Forward Reserve Resources.

The Internal Market Monitor will receive information that will identify Forward Reserve Resources, the Forward Reserve Threshold Price, and the assigned Forward Reserve Obligation. Prior to mitigation of Supply Offers or Demand Bids associated with a Forward Reserve Resource, the Internal Market Monitor shall consult with the Market Participant in accordance with Section III.A.3 of this ***Appendix A***. The Internal Market Monitor and the Market Participant shall consider the impact on meeting any Forward Reserve Obligations in those consultations. If mitigation is imposed, any mitigated offers shall be used in the calculation of qualifying megawatts under Section III.9.6.4 of Market Rule 1.

III.A.13.5. Imposition of Sanctions.

Appendix B of Market Rule 1 sets forth the procedures and standards under which sanctions may be imposed for certain violations of Market Participants' obligations under the ISO New England Filed Documents and other ISO New England System Rules. The Internal Market Monitor shall administer ***Appendix B*** in accordance with the provisions thereof.

III.A.14. Treatment of Supply Offers for Resources Subject to a Cost-of-Service Agreement.

Article 5 of the form of Cost-of-Service Agreement in ***Appendix I*** to Market Rule 1 addresses the monitoring of resources subject to a cost-of-service agreement by the Internal Market Monitor and External Market Monitor. Pursuant to Section 5.2 of Article 5 of the Form of Cost-of-Service Agreement, after consultation with the Lead Market Participant, Supply Offers that exceed Stipulated Variable Cost as determined in the agreement are subject to adjustment by the Internal Market Monitor to Stipulated Variable Cost.

III.A.15. Request for Additional Cost Recovery.

III.A.15.1. Cost Recovery Request Following Capping.

If as a result of an offer being capped under Section III.1.9, a Market Participant believes that it will not recover the fuel and variable operating and maintenance costs of the Resource, as reflected in the offer, for the hours of the Operating Day during which the offer was capped, the Market Participant may, within 20 days of the receipt of the first Invoice issued containing credits or charges for the applicable Operating Day, submit an additional cost recovery request to the Internal Market Monitor.

A request under this Section III.A.15 may seek recovery of additional costs incurred for the duration of the period of time for which the Resource was operated at the cap.

III.A.15.1.1. Timing and Contents of Request.

Within 20 days of the receipt of the first Invoice containing credits or charges for the applicable Operating Day, a Market Participant requesting additional cost recovery under this Section III.A.15.1 shall submit to the Internal Market Monitor a request in writing detailing: (i) the actual fuel and variable operating and maintenance costs for the Resource for the applicable Operating Days, with supporting data, documentation and calculations for those costs; and (ii) an explanation of why the actual costs of operating the Resource exceeded the capped costs.

III.A.15.1.2. Review by Internal Market Monitor.

To evaluate a Market Participant's request, the Internal Market Monitor shall use the data, calculations and explanations provided by the Market Participant to verify the actual fuel and variable operating and maintenance costs for the Resource for the applicable Operating Days, using the same standards and methodologies the Internal Market Monitor uses to evaluate requests to update Reference Levels under Section III.A.3 of Appendix A. To the extent the Market Participant's request warrants additional cost recovery, the Internal Market Monitor shall reflect that adjustment in the Resource's Reference Levels for the period covered by the request. The ISO shall then re-apply the cost verification and capping formulas in Section III.1.9 using the updated Reference Levels to re-calculate the adjustments to the Market Participant's offers required thereunder, and then shall calculate additional cost recovery using the adjusted offer values.

Within 20 days of the receipt of a completed submittal, the Internal Market Monitor shall provide a written response to the Market Participant's request, detailing (i) the extent to which it agrees with the request with supporting explanation, and (ii) a calculation of the additional cost recovery. Changes to

credits and charges resulting from an additional cost recovery request shall be included in the Data Reconciliation Process.

III.A.15.1.3. Cost Allocation.

The ISO shall allocate charges to Market Participants for payment of any additional cost recovery granted under this Section III.A.15.1 in accordance with the cost allocation provisions of Market Rule 1 that otherwise would apply to payments for the services provided based on the Resource's actual dispatch for the Operating Days in question.

III.A.15.2. Section 205 Filing Right.

If either

(a) as a result of mitigation applied to a Resource under this ***Appendix A*** for all or part of one or more Operating Days, or

(b) in the absence of mitigation, as a result of a request under Section III.A.15.1 being denied in whole or in part,

a Market Participant believes that it will not recover the fuel and variable operating and maintenance costs of the Resource, as reflected in the offer, for the hours of the Operating Day during which the offer was mitigated or the Section III.A.15.1 request was denied, the Market Participant may submit a filing to the Commission seeking recovery of those costs pursuant to Section 205 of the Federal Power Act. For filings to address cost recovery under Section III.A.15.2(a), the filing must be made within sixty days of receipt of the first Invoice issued containing credits or charges for the applicable Operating Day. For filings to address cost recovery under Section III.A.15.2(b), the filing must be made within sixty days of receipt of the first Invoice issued that reflects the denied request for additional cost recovery under Section III.A.15.1.

A request under this Section III.A.15.2 may seek recovery of additional costs incurred during the following periods: (a) if as a result of mitigation, costs incurred for the duration of the mitigation event, and (b) if as a result of having a Section III.A.15.1 request denied, costs incurred for the duration of the period of time addressed in the Section III.A.15.1 request.

III.A.15.2.1. Contents of Filing.

Any Section 205 filing made pursuant to this section shall include: (i) the actual fuel and variable operating and maintenance costs for the Resource for the applicable Operating Days, with supporting data

and calculations for those costs; (ii) an explanation of (a) why the actual costs of operating the Resource exceeded the Reference Level costs or, (b) in the absence of mitigation, why the actual costs of operating the Resource, as reflected in the original offer and to the extent not recovered under Section III.A.15.1, exceeded the costs as reflected in the capped offer; (iii) the Internal Market Monitor's written explanation provided pursuant to Section III.A.15.3; and (iv) all requested regulatory costs in connection with the filing.

III.A.15.2.2. Review by Internal Market Monitor Prior to Filing.

Within twenty days of the receipt of the applicable Invoice, a Market Participant that intends to make a Section 205 filing pursuant to this Section III.A.15.2 shall submit to the Internal Market Monitor the information and explanation detailed in Section III.A.15.2.1 (i) and (ii) that is to be included in the Section 205 filing. Within twenty days of the receipt of a completed submittal, the Internal Market Monitor shall provide a written explanation of the events that resulted in the Section III.A.15.2 request for additional cost recovery. The Market Participant shall include the Internal Market Monitor's written explanation in the Section 205 filing made pursuant to this Section III A.15.2.

III.A.15.2.3. Cost Allocation.

In the event that the Commission accepts a Market Participant's filing for cost recovery under this section, the ISO shall allocate charges to Market Participants for payment of those costs in accordance with the cost allocation provisions of Market Rule 1 that otherwise would apply to payments for the services provided based on the Resource's actual dispatch for the Operating Days in question.

III.A.16. ADR Review of Internal Market Monitor Mitigation Actions.

III.A.16.1. Actions Subject to Review.

A Market Participant may obtain prompt Alternative Dispute Resolution ("ADR") review of any Internal Market Monitor mitigation imposed on a Resource as to which that Market Participant has bidding or operational authority. A Market Participant must seek review pursuant to the procedure set forth in ***Appendix D*** to this Market Rule 1, but in all cases within the time limits applicable to billing adjustment requests. These deadlines are currently specified in the ISO New England Manuals. Actions subject to review are:

- Imposition of a mitigation remedy.

- Continuation of a mitigation remedy as to which a Market Participant has submitted material evidence of changed facts or circumstances. (Thus, after a Market Participant has unsuccessfully challenged imposition of a mitigation remedy, it may challenge the continuation of that mitigation in a subsequent ADR review on a showing of material evidence of changed facts or circumstances.)

III.A.16.2. Standard of Review.

On the basis of the written record and the presentations of the Internal Market Monitor and the Market Participant, the ADR Neutral shall review the facts and circumstances upon which the Internal Market Monitor based its decision and the remedy imposed by the Internal Market Monitor. The ADR Neutral shall remove the Internal Market Monitor's mitigation only if it concludes that the Internal Market Monitor's application of the Internal Market Monitor mitigation policy was clearly erroneous. In considering the reasonableness of the Internal Market Monitor's action, the ADR Neutral shall consider whether adequate opportunity was given to the Market Participant to present information, any voluntary remedies proposed by the Market Participant, and the need of the Internal Market Monitor to act quickly to preserve competitive markets.

III.A.17. Reporting.

III.A.17.1. Data Collection and Retention.

Market Participants shall provide the Internal Market Monitor and External Market Monitor with any and all information within their custody or control that the Internal Market Monitor or External Market Monitor deems necessary to perform its obligations under this ***Appendix A***, subject to applicable confidentiality limitations contained in the ISO New England Information Policy. This would include a Market Participant's cost information if the Internal Market Monitor or External Market Monitor deems it necessary, including start up, no-load and all other actual marginal costs, when needed for monitoring or mitigation of that Market Participant. Additional data requirements may be specified in the ISO New England Manuals. If for any reason the requested explanation or data is unavailable, the Internal Market Monitor and External Market Monitor will use the best information available in carrying out their responsibilities. The Internal Market Monitor and External Market Monitor may use any and all information they receive in the course of carrying out their market monitor and mitigation functions to the extent necessary to fully perform those functions.

Market Participants must provide data and any other information requested by the Internal Market Monitor that the Internal Market Monitor requests to determine:

(a) the opportunity costs associated with Demand Reduction Offers;

(b) the accuracy of Demand Response Baselines;

(c) the method used to achieve a demand reduction, and;

(d) the accuracy of metered demand reported to the ISO.

III.A.17.2. Periodic Reporting by the ISO and Internal Market Monitor.

III.A.17.2.1. Monthly Report.

The ISO will prepare a monthly report, which will be available to the public both in printed form and electronically, containing an overview of the market's performance in the most recent period.

III.A.17.2.2. Quarterly Report.

The Internal Market Monitor will prepare a quarterly report consisting of market data regularly collected by the Internal Market Monitor in the course of carrying out its functions under this ***Appendix A*** and analysis of such market data. Final versions of such reports shall be disseminated contemporaneously to the Commission, the ISO Board of Directors, the Market Participants, and state public utility commissions for each of the six New England states, provided that in the case of the Market Participants and public utility commissions, such information shall be redacted as necessary to comply with the ISO New England Information Policy. The format and content of the quarterly reports will be updated periodically through consensus of the Internal Market Monitor, the Commission, the ISO, the public utility commissions of the six New England States and Market Participants. The entire quarterly report will be subject to confidentiality protection consistent with the ISO New England Information Policy and the recipients will ensure the confidentiality of the information in accordance with state and federal laws and regulations. The Internal Market Monitor will make available to the public a redacted version of such quarterly reports. The Internal Market Monitor, subject to confidentiality restrictions, may decide whether and to what extent to share drafts of any report or portions thereof with the Commission, the ISO, one or more state public utility commission(s) in New England or Market Participants for input and verification before the report is finalized. The Internal Market Monitor shall keep the Market Participants informed of the progress of any report being prepared pursuant to the terms of this ***Appendix A.***

III.A.17.2.3. Reporting on General Performance of the Forward Capacity Market.

The performance of the Forward Capacity Market, including reconfiguration auctions, shall be subject to the review of the Internal Market Monitor. No later than 180 days after the completion of the second Forward Capacity Auction, the Internal Market Monitor shall file with the Commission and post to the ISO's website a full report analyzing the operations and effectiveness of the Forward Capacity Market. Thereafter, the Internal Market Monitor shall report on the functioning of the Forward Capacity Market in its annual markets report in accordance with the provisions of Section III.A.17.2.4 of this ***Appendix A***.

III.A.17.2.4. Annual Review and Report by the Internal Market Monitor.

The Internal Market Monitor will prepare an annual state of the market report on market trends and the performance of the New England Markets and will present an annual review of the operations of the New England Markets. The annual report and review will include an evaluation of the procedures for the determination of energy, reserve and regulation clearing prices, NCPC costs and the performance of the Forward Capacity Market and FTR Auctions. The review will include a public forum to discuss the performance of the New England Markets, the state of competition, and the ISO's priorities for the coming year. In addition, the Internal Market Monitor will arrange a non-public meeting open to appropriate state or federal government agencies, including the Commission and state regulatory bodies, attorneys general, and others with jurisdiction over the competitive operation of electric power markets, subject to the confidentiality protections of the ISO New England Information Policy, to the greatest extent permitted by law.

III.A.17.2.5. Additional Ad Hoc Reporting on Performance and Competiveness of Markets

Commencing on June 1, 2024, in furtherance of its functions under Section III.A.2 of this Appendix A, including without limitation Sections III.A.2.3 (e) and (k) therein, the Internal Market Monitor shall perform independent evaluations and prepare ad hoc reports on the overall competitiveness and performance of the New England Markets or particular aspects of the New England Markets, including the competitiveness and performance of a major market design change. The Internal Market Monitor shall have the sole discretion to determine when to prepare an ad hoc report and may prepare such report on its own initiative or pursuant to a request by the ISO, New England state public utility commissions or one or more Market Participants. However, the Internal Market Monitor will report on the competitiveness and performance of any new major market design change within one to three years, respectively, of the effective date of

operation of the market design change, or as soon as adequate data becomes available. While the Internal Market Monitor may solicit and/or receive input of the External Market Monitor, Market Participants and other stakeholders, including New England state public utility commissions, the methodology and criteria used to conduct its independent analysis shall be at the sole discretion of the Internal Market Monitor. The Internal Market Monitor shall describe its methodology and criteria used in an ad hoc report of its significant findings and, if any, recommendations. The Internal Market Monitor shall file with the Commission and post to the ISO's website a final version of an ad hoc report. Thereafter, the Internal Market Monitor shall continue to report on the competitiveness and performance of any market design change that has been the subject of an ad hoc report in its quarterly and/or annual reports under Sections III.A.17.2.2 and III.A.17.2.4.

III.A.17.3. Periodic Reporting by the External Market Monitor.

The External Market Monitor will perform independent evaluations and prepare annual and ad hoc reports on the overall competitiveness and efficiency of the New England Markets or particular aspects of the New England Markets, including the adequacy of ***Appendix A***. The External Market Monitor shall have the sole discretion to determine whether and when to prepare ad hoc reports and may prepare such reports on its own initiative or pursuant to requests by the ISO, state public utility commissions or one or more Market Participants. Final versions of such reports shall be disseminated contemporaneously to the Commission, the ISO Board of Directors, the Market Participants, and state public utility commissions for each of the six New England states, provided that in the case of the Market Participants and public utility commissions, such information shall be redacted as necessary to comply with the ISO New England Information Policy. Such reports shall, at a minimum, include:

(i) Review and assessment of the practices, market rules, procedures, protocols and other activities of the ISO insofar as such activities, and the manner in which the ISO implements such activities, affect the competitiveness and efficiency of New England Markets.

(ii) Review and assessment of the practices, procedures, protocols and other activities of any independent transmission company, transmission provider or similar entity insofar as its activities affect the competitiveness and efficiency of the New England Markets.

(iii) Review and assessment of the activities of Market Participants insofar as these activities affect the competitiveness and efficiency of the New England Markets.

(iv) Review and assessment of the effectiveness of ***Appendix A*** and the administration of ***Appendix A*** by the Internal Market Monitor for consistency and compliance with the terms of ***Appendix A.***

(v) Review and assessment of the relationship of the New England Markets with any independent transmission company and with adjacent markets.

The External Market Monitor, subject to confidentiality restrictions, may decide whether and to what extent to share drafts of any report or portions thereof with the Commission, the ISO, one or more state public utility commission(s) in New England or Market Participants for input and verification before the report is finalized. The External Market Monitor shall keep the Market Participants informed of the progress of any report being prepared.

III.A.17.4. Other Internal Market Monitor or External Market Monitor Communications With Government Agencies.

III.A.17.4.1. Routine Communications.

The periodic reviews are in addition to any routine communications the Internal Market Monitor or External Market Monitor may have with appropriate state or federal government agencies, including the Commission and state regulatory bodies, attorneys general, and others with jurisdiction over the competitive operation of electric power markets.

III.A.17.4.2. Additional Communications.

The Internal Market Monitor and External Market Monitor are not a regulatory or enforcement agency. However, they will monitor market trends, including changes in Resource ownership as well as market performance. In addition to the information on market performance and mitigation provided in the monthly, quarterly and annual reports the External Market Monitor or Internal Market Monitor shall:

(a) Inform the jurisdictional state and federal regulatory agencies, as well as the Markets Committee, if the External Market Monitor or Internal Market Monitor determines that a market problem appears to be developing that will not be adequately remediable by existing market rules or mitigation measures;

(b) If the External Market Monitor or Internal Market Monitor receives information from any entity regarding an alleged violation of law, refer the entity to the appropriate state or federal agencies;

(c) If the External Market Monitor or Internal Market Monitor reasonably concludes, in the normal course of carrying out its monitoring and mitigation responsibilities, that certain

market conduct constitutes a violation of law, report these matters to the appropriate state and federal agencies; and,

(d) Provide the names of any companies subjected to mitigation under these procedures as well as a description of the behaviors subjected to mitigation and any mitigation remedies or sanctions applied.

III.A.17.4.3. Confidentiality.

Information identifying particular participants required or permitted to be disclosed to jurisdictional bodies under this section shall be provided in a confidential report filed under Section 388.112 of the Commission regulations and corresponding provisions of other jurisdictional agencies. The Internal Market Monitor will include the confidential report with the quarterly submission it provides to the Commission pursuant to Section III.A.17.2.2.

III.A.17.5. Other Information Available from Internal Market Monitor and External Market Monitor on Request by Regulators.

The Internal Market Monitor and External Market Monitor will normally make their records available as described in this paragraph to authorized state or federal agencies, including the Commission and state regulatory bodies, attorneys general and others with jurisdiction over the competitive operation of electric power markets ("authorized government agencies"). With respect to state regulatory bodies and state attorneys general ("authorized state agencies"), the Internal Market Monitor and External Market Monitor shall entertain information requests for information regarding general market trends and the performance of the New England Markets, but shall not entertain requests that are designed to aid enforcement actions of a state agency. The Internal Market Monitor and External Market Monitor shall promptly make available all requested data and information that they are permitted to disclose to authorized government agencies under the ISO New England Information Policy. Notwithstanding the foregoing, in the event an information request is unduly burdensome in terms of the demands it places on the time and/or resources of the Internal Market Monitor or External Market Monitor, the Internal Market Monitor or External Market Monitor shall work with the authorized government agency to modify the scope of the request or the time within which a response is required, and shall respond to the modified request.

The Internal Market Monitor and External Market Monitor also will comply with compulsory process, after first notifying the owner(s) of the items and information called for by the subpoena or civil investigative demand and giving them at least ten Business Days to seek to modify or quash the compulsory process. If an authorized government agency makes a request in writing, other than

compulsory process, for information or data whose disclosure to authorized government agencies is not permitted by the ISO New England Information Policy, the Internal Market Monitor and External Market Monitor shall notify each party with an interest in the confidentiality of the information and shall process the request under the applicable provisions of the ISO New England Information Policy. Requests from the Commission for information or data whose disclosure is not permitted by the ISO New England Information Policy shall be processed under Section 3.2 of the ISO New England Information Policy. Requests from authorized state agencies for information or data whose disclosure is not permitted by the ISO New England Information Policy shall be processed under Section 3.3 of the ISO New England Information Policy. In the event confidential information is ultimately released to an authorized state agency in accordance with Section 3.3 of the ISO New England Information Policy, any party with an interest in the confidentiality of the information shall be permitted to contest the factual content of the information, or to provide context to such information, through a written statement provided to the Internal Market Monitor or External Market Monitor and the authorized state agency that has received the information.

III.A.18. Ethical Conduct Standards.

III.A.18.1. Compliance with ISO New England Inc. Code of Conduct.
The employees of the ISO that perform market monitoring and mitigation services for the ISO and the employees of the External Market Monitor that perform market monitoring and mitigation services for the ISO shall execute and shall comply with the terms of the ISO New England Inc. Code of Conduct attached hereto as ***Exhibit 5***.

III.A.18.2. Additional Ethical Conduct Standards.
The employees of the ISO that perform market monitoring and mitigation services for the ISO and the employees of the External Market Monitor that perform market monitoring and mitigation services for the ISO shall also comply with the following additional ethical conduct standards. In the event of a conflict between one or more standards set forth below and one or more standards contained in the ISO New England Inc. Code of Conduct, the more stringent standard(s) shall control.

III.A.18.2.1. Prohibition on Employment with a Market Participant.
No such employee shall serve as an officer, director, employee or partner of a Market Participant.

III.A.18.2.2. Prohibition on Compensation for Services.

No such employee shall be compensated, other than by the ISO or, in the case of employees of the External Market Monitor, by the External Market Monitor, for any expert witness testimony or other commercial services, either to the ISO or to any other party, in connection with any legal or regulatory proceeding or commercial transaction relating to the ISO or the New England Markets.

III.A.18.2.3. Additional Standards Applicable to External Market Monitor.

In addition to the standards referenced in the remainder of this Section 18 of ***Appendix A***, the employees of the External Market Monitor that perform market monitoring and mitigation services for the ISO are subject to conduct standards set forth in the External Market Monitor Services Agreement entered into between the External Market Monitor and the ISO, as amended from time-to-time. In the event of a conflict between one or more standards set forth in the External Market Monitor Services Agreement and one or more standards set forth above or in the ISO New England Inc. Code of Conduct, the more stringent standard(s) shall control.

III.A.19. Protocols on Referral to the Commission of Suspected Violations.

(A) The Internal Market Monitor or External Market Monitor is to make a non-public referral to the Commission in all instances where the Internal Market Monitor or External Market Monitor has reason to believe that a Market Violation has occurred. While the Internal Market Monitor or External Market Monitor need not be able to prove that a Market Violation has occurred, the Internal Market Monitor or External Market Monitor is to provide sufficient credible information to warrant further investigation by the Commission. Once the Internal Market Monitor or External Market Monitor has obtained sufficient credible information to warrant referral to the Commission, the Internal Market Monitor or External Market Monitor is to immediately refer the matter to the Commission and desist from independent action related to the alleged Market Violation. This does not preclude the Internal Market Monitor or External Market Monitor from continuing to monitor for any repeated instances of the activity by the same or other entities, which would constitute new Market Violations. The Internal Market Monitor or External Market Monitor is to respond to requests from the Commission for any additional information in connection with the alleged Market Violation it has referred.

(B) All referrals to the Commission of alleged Market Violations are to be in writing, whether transmitted electronically, by fax, mail or courier. The Internal Market Monitor or External Market Monitor may alert the Commission orally in advance of the written referral.

(C) The referral is to be addressed to the Commission's Director of the Office of Enforcement, with a copy also directed to both the Director of the Office of Energy Market Regulation and the General Counsel.

(D) The referral is to include, but need not be limited to, the following information

(1) The name(s) of and, if possible, the contact information for, the entity(ies) that allegedly took the action(s) that constituted the alleged Market Violation(s);

(2) The date(s) or time period during which the alleged Market Violation(s) occurred and whether the alleged wrongful conduct is ongoing;

(3) The specific rule or regulation, and/or tariff provision, that was allegedly violated, or the nature of any inappropriate dispatch that may have occurred;

(4) The specific act(s) or conduct that allegedly constituted the Market Violation;

(5) The consequences to the market resulting from the acts or conduct, including, if known, an estimate of economic impact on the market;

(6) If the Internal Market Monitor or External Market Monitor believes that the act(s) or conduct constituted a violation of the anti-manipulation rule of Part 1c of the Commission's Rules and Regulations, 18 C.F.R. Part 1c, a description of the alleged manipulative effect on market prices, market conditions, or market rules;

(7) Any other information the Internal Market Monitor or External Market Monitor believes is relevant and may be helpful to the Commission.

(E) Following a referral to the Commission, the Internal Market Monitor or External Market Monitor is to continue to notify and inform the Commission of any information that the Internal Market Monitor or External Market Monitor learns of that may be related to the referral, but the Internal Market Monitor or External Market Monitor is not to undertake any investigative steps regarding the referral except at the express direction of the Commission or Commission staff.

III.A.20. Protocol on Referrals to the Commission of Perceived Market Design Flaws and Recommended Tariff Changes.

(A) The Internal Market Monitor or External Market Monitor is to make a referral to the Commission in all instances where the Internal Market Monitor or External Market Monitor has reason to believe market design flaws exist that it believes could effectively be remedied by rule or tariff changes. The Internal Market Monitor or External Market Monitor must limit distribution of its identifications and recommendations to the ISO and to the Commission in the event it believes broader dissemination could lead to exploitation, with an explanation of why further dissemination should be avoided at that time.

(B) All referrals to the Commission relating to perceived market design flaws and recommended tariff changes are to be in writing, whether transmitted electronically, by fax, mail, or courier. The Internal Market Monitor or External Market Monitor may alert the Commission orally in advance of the written referral.

(C) The referral should be addressed to the Commission's Director of the Office of Energy Market Regulation, with copies directed to both the Director of the Office of Enforcement and the General Counsel.

(D) The referral is to include, but need not be limited to, the following information.

   (1) A detailed narrative describing the perceived market design flaw(s);

   (2) The consequences of the perceived market design flaw(s), including, if known, an estimate of economic impact on the market;

   (3) The rule or tariff change(s) that the Internal Market Monitor or External Market Monitor believes could remedy the perceived market design flaw;

   (4) Any other information the Internal Market Monitor or External Market Monitor believes is relevant and may be helpful to the Commission.

(E) Following a referral to the Commission, the Internal Market Monitor or External Market Monitor is to continue to notify and inform the Commission of any additional information regarding the perceived market design flaw, its effects on the market, any additional or modified observations concerning the rule or tariff changes that could remedy the perceived design flaw, any recommendations made by the Internal Market Monitor or External Market Monitor to the regional transmission organization or independent system operator, stakeholders, market participants or state commissions regarding the perceived design flaw, and any actions taken by the regional transmission organization or independent system operator regarding the perceived design flaw.

III.A.21. Review of Offers From New Resources in the Forward Capacity Market.

The Internal Market Monitor shall review offers from new resources in the Forward Capacity Auction as described in this Section III.A.21.

III.A.21.1. Offer Review Trigger Prices.

For each new technology type, the Internal Market Monitor shall establish an Offer Review Trigger Price. Offers in the Forward Capacity Auction at prices that are equal to or above the relevant Offer Review Trigger Price will not be subject to further review by the Internal Market Monitor. A request to submit offers in the Forward Capacity Auction at prices that are below the relevant Offer Review Trigger Price must be submitted in advance of the Forward Capacity Auction as described in Sections III.13.1.1.2.2.3,

III.13.1.3.5 or III.13.1.4.1.1.2.8 and shall be reviewed by the Internal Market Monitor as described in this Section III.A.21.

III.A.21.1.1. Offer Review Trigger Prices for the Forward Capacity Auction.

For resources other than New Import Capacity Resources, the Offer Review Trigger Prices for the twelfth Forward Capacity Auction (for the Capacity Commitment Period beginning on June 1, 2021) shall be as follows:

Generating Capacity Resources	
Technology Type	**Offer Review Trigger Price ($/kW-month)**
combustion turbine	$6.503
combined cycle gas turbine	$7.856
on-shore wind	$11.025

Demand Capacity Resources - Commercial and Industrial	
Technology Type	**Offer Review Trigger Price ($/kW-month)**
Load Management and/or previously installed Distributed Generation	$1.008
new Distributed Generation	based on generation technology type
Energy Efficiency	$0.000

Demand Capacity Resources – Residential	
Technology Type	**Offer Review Trigger Price ($/kW-month)**
Load Management	$7.559
previously installed Distributed Generation	$1.008
new Distributed Generation	based on generation technology type
Energy Efficiency	$0.000

Other Resources	
All other technology types	Forward Capacity Auction Starting Price

Where a new resource is composed of assets having different technology types, the resource's Offer Review Trigger Price will be calculated in accordance with the weighted average formula in Section III.A.21.2(c).

For purposes of determining the Offer Review Trigger Price of a Demand Capacity Resource composed in whole or in part of Distributed Generation, the Distributed Generation is considered new, rather than previously installed, if (1) the Project Sponsor for the New Demand Capacity Resource has participated materially in the development, installation or funding of the Distributed Generation during the five years prior to commencement of the Capacity Commitment Period for which the resource is being qualified for participation, and (2) the Distributed Generation has not been assigned to a Demand Capacity Resource with a Capacity Supply Obligation in a prior Capacity Commitment Period.

For a New Import Capacity Resource that is backed by a single new External Resource and that is associated with an investment in transmission that increases New England's import capability, the Offer Review Trigger Prices in the table above shall apply, based on the technology type of the External Resource; provided that, if a New Import Capacity Resource is associated with an Elective Transmission Upgrade, it shall have an Offer Review Trigger Price of the Forward Capacity Auction Starting Price plus $0.01/kW-month.

For any other New Import Capacity Resource, the Offer Review Trigger Price shall be the Forward Capacity Auction Starting Price plus $0.01/kW-month.

III.A.21.1.2. Calculation of Offer Review Trigger Prices.

(a) The Offer Review Trigger Price for each of the technology types listed above shall be recalculated using updated data for the Capacity Commitment Period beginning on June 1, 2025 and no less often than once every three years thereafter. Where any Offer Review Trigger Price is recalculated, the Internal Market Monitor will review the results of the recalculation with stakeholders and the new Offer Review Trigger Price shall be filed with the Commission prior to the Forward Capacity Auction in which the Offer Review Trigger Price is to apply.

(b) For New Generating Capacity Resources, the methodology used to recalculate the Offer Review Trigger Price pursuant to subsection (a) above is as follows. Capital costs, expected non-capacity revenues and operating costs, assumptions regarding depreciation, taxes and discount rate are input into a capital budgeting model which is used to calculate the break-even contribution required from the Forward

Capacity Market to yield a discounted cash flow with a net present value of zero for the project. The Offer Review Trigger Price is set equal to the year-one capacity price output from the model. The model looks at 20 years of real-dollar cash flows discounted at a rate (Weighted Average Cost of Capital) consistent with that expected of a project whose output is under contract (i.e., a contract negotiated at arm's length between two unrelated parties).

(c) For New Demand Capacity Resources comprised of Energy Efficiency, the methodology used to recalculate the Offer Review Trigger Price pursuant to subsection (a) above shall be the same as that used for New Generating Capacity Resources, with the following exceptions. First, the model takes account of all costs incurred by the utility and end-use customer to deploy the efficiency measure. Second, rather than energy revenues, the model recognizes end-use customer savings associated with the efficiency programs. Third, the model assumes that all costs are expensed as incurred. Fourth, the benefits realized by end-use customers are assumed to have no tax implications for the utility. Fifth, the model discounts cash flows over the Measure Life of the energy efficiency measure.

(d) For New Demand Capacity Resources other than Demand Capacity Resources comprised of Energy Efficiency, the methodology used to recalculate the Offer Review Trigger Price pursuant to subsection (a) above is the same as that used for New Generating Capacity Resources, except that the model discounts cash flows over the contract life. For Demand Capacity Resources (other than those comprised of Energy Efficiency) that are composed primarily of large commercial or industrial customers that use pre-existing equipment or strategies, incremental costs include new equipment costs and annual operating costs such as customer incentives and sales representative commissions. For Demand Capacity Resources (other than Demand Capacity Resources comprised of Energy Efficiency) primarily composed of residential or small commercial customers that do not use pre-existing equipment or strategies, incremental costs include equipment costs, customer incentives, marketing, sales, and recruitment costs, operations and maintenance costs, and software and network infrastructure costs.

(e) For years in which no full recalculation is performed pursuant to subsection (a) above, the Offer Review Trigger Prices will be adjusted as follows:

(1) Each line item associated with capital costs that is included in the capital budgeting model will be associated with the indices included in the table below:

Cost Component	**Index**
gas turbines	BLS-PPI "Turbines and Turbine Generator Sets"

steam turbines	BLS-PPI "Turbines and Turbine Generator Sets"
wind turbines	Bloomberg Wind Turbine Price Index
Other Equipment	BLS-PPI "General Purpose Machinery and Equipment"
construction labor	BLS “Quarterly Census of Employment and Wages” 2371 Utility System Construction Average Annual Pay: – Combustion turbine and combined cycle gas turbine costs to be indexed to values corresponding to the location of Hampden County, Massachusetts – On-shore wind costs to be indexed to values corresponding to the location of Cumberland County, Maine
other labor	BLS “Quarterly Census of Employment and Wages” 2211 Power Generation and Supply Average Annual Pay: – Combustion turbine and combined cycle gas turbine costs to be indexed to values corresponding to the location of Hampden County, Massachusetts – On-shore wind costs to be indexed to values corresponding to the location of Cumberland County, Maine
materials	BLS-PPI "Materials and Components for Construction"
electric interconnection	BLS - PPI "Electric Power Transmission, Control, and Distribution"
gas interconnection	BLS - PPI "Natural Gas Distribution: Delivered to ultimate consumers for the account of others (transportation only)”
fuel inventories	Federal Reserve Bank of St. Louis “Gross Domestic Product: Implicit Price Deflator (GDPDEF)”

(2) Each line item associated with fixed operating and maintenance costs that is included in the capital budgeting model will be associated with the indices included in the table below:

Cost Component	**Index**
labor, administrative and general	BLS “Quarterly Census of Employment and Wages” 2211 Power Generation and Supply Average Annual Pay: – Combustion turbine and combined cycle gas turbine costs to be indexed to values corresponding to the location of Hampden County, Massachusetts – On-shore wind costs to be indexed to values corresponding to the location of Cumberland County, Maine
materials and contract services	BLS-PPI "Materials and Components for Construction"
site leasing costs	Federal Reserve Bank of St. Louis “Gross Domestic Product: Implicit Price Deflator (GDPDEF)”

(3) For each line item in (1) and (2) above, the ISO shall calculate a multiplier that is equal to the average of values published during the most recent 12 month period available at the time of making the adjustment divided by the average of the most recent 12 month period available at the time of establishing the Offer Review Trigger Prices for the FCA reflected in the table in Section III.A.21.1.1 above. The value of each line item associated with capital costs and fixed operating and maintenance costs included

in the capital budgeting model for the FCA reflected in the table in Section A.21.1.1 above will be adjusted by the relevant multiplier.

(4) The energy and ancillary services offset values for each technology type in the capital budgeting model shall be adjusted by inputting to the capital budgeting model the most recent Henry Hub natural gas futures prices, the Algonquin Citygates Basis natural gas futures prices and the Massachusetts Hub On-Peak electricity prices for the months in the Capacity Commitment Period beginning June 1, 2021, as published by ICE.

(5) Renewable energy credit values in the capital budgeting model shall be updated based on the most recent MA Class 1 REC price for the vintage closest to the first year of the Capacity Commitment Period associated with the relevant FCA as published by SNL Financial.

(6) The capital budgeting model and the Offer Review Trigger Prices adjusted pursuant to this subsection (e) will be published on the ISO's web site.

(7) If any of the values required for the calculations described in this subsection (e) are unavailable, then comparable values, prices or sources shall be used.

III.A.21.2. New Resource Offer Floor Prices and Offer Prices.

For every new resource participating in a Forward Capacity Auction, the Internal Market Monitor shall determine a New Resource Offer Floor Price or offer prices, as described in this Section III.A.21.2.

(a) For a Lead Market Participant with a New Capacity Resource that does not submit a request to submit offers in the Forward Capacity Auction at prices that are below the relevant Offer Review Trigger Price as described in Sections III.13.1.1.2.2.3, III.13.1.3.5 or III.13.1.4.1.1.2.8, the New Resource Offer Floor Price shall be calculated as follows:

> For a New Import Capacity Resource (other than a New Import Capacity Resource that is (i) backed by a single new External Resource and that is associated with an investment in transmission that increases New England's import capability or (ii) associated with an Elective Transmission Upgrade) the New Resource Offer Floor Price shall be $0.00/kW-month.

For a New Generating Capacity Resource, New Import Capacity Resource that is backed by a single new External Resource and that is associated with an investment in transmission that increases New England's import capability, New Import Capacity Resource that is associated with an Elective Transmission Upgrade, and New Demand Capacity Resource, the New Resource Offer Floor Price shall be equal to the applicable Offer Review Trigger Price.

A resource having a New Resource Offer Floor Price higher than the Forward Capacity Auction Starting Price shall not be included in the Forward Capacity Auction.

(b) For a Lead Market Participant with a New Capacity Resource that does submit a request to submit offers in the Forward Capacity Auction at prices that are below the relevant Offer Review Trigger Price as described in Sections III.13.1.1.2.2.3, III.13.1.3.5 and III.13.1.4.1.1.2.8, the resource's New Resource Offer Floor Price and offer prices in the case of a New Import Capacity Resource (other than a New Import Capacity Resource that is backed by a single new External Resource and that is associated with an investment in transmission that increases New England's import capability or a New Import Capacity Resource that is associated with an Elective Transmission Upgrade) shall be calculated as follows:

For a New Import Capacity Resource that is subject to the pivotal supplier test in Section III.A.23 and is found not to be associated with a pivotal supplier as determined pursuant to Section III.A.23, the resource's New Resource Offer Floor Price and offer prices shall be equal to the lower of (i) the requested offer price submitted to the ISO as described in Sections III.13.1.1.2.2.3 and III.13.1.3.5; or (ii) the price revised pursuant to Section III.13.1.3.5.7.

For any other New Capacity Resource, the Internal Market Monitor shall enter all relevant resource costs and non-capacity revenue data, as well as assumptions regarding depreciation, taxes, and discount rate into the capital budgeting model used to develop the relevant Offer Review Trigger Price and shall calculate the break-even contribution required from the Forward Capacity Market to yield a discounted cash flow with a net present value of zero for the project. The Internal Market Monitor shall compare the requested offer price to this capacity price estimate and the resource's New Resource Offer Floor Price and offer prices shall be determined as follows:

(i) The Internal Market Monitor will exclude any out-of-market revenue sources from the cash flows used to evaluate the requested offer price. Out-of-market revenues are any revenues that are: (a) not tradable throughout the New England Control Area or that are restricted to resources

within a particular state or other geographic sub-region; or (b) not available to all resources of the same physical type within the New England Control Area, regardless of the resource owner. Expected revenues associated with economic development incentives that are offered broadly by state or local government and that are not expressly intended to reduce prices in the Forward Capacity Market are not considered out-of-market revenues for this purpose. In submitting its requested offer price, the Project Sponsor shall indicate whether and which project cash flows are supported by a regulated rate, charge, or other regulated cost recovery mechanism. If the project is supported by a regulated rate, charge, or other regulated cost recovery mechanism, then that rate will be replaced with the Internal Market Monitor estimate of energy revenues. Where possible, the Internal Market Monitor will use like-unit historical production, revenue, and fuel cost data. Where such information is not available (e.g., there is no resource of that type in service), the Internal Market Monitor will use a forecast provided by a credible third party source. The Internal Market Monitor will review capital costs, discount rates, depreciation and tax treatment to ensure that it is consistent with overall market conditions. Any assumptions that are clearly inconsistent with prevailing market conditions will be adjusted.

(ii) For a New Demand Capacity Resource, the resource's costs shall include all expenses, including incentive payments, equipment costs, marketing and selling and administrative and general costs incurred to acquire and/or develop the Demand Capacity Resource. Revenues shall include all non-capacity payments expected from the ISO-administered markets made for services delivered from the associated Demand Response Resource, and expected costs avoided by the associated end-use customer as a direct result of the installation or implementation of the associated Asset(s).

(iii) For a New Capacity Resource that has achieved commercial operation prior to the New Capacity Qualification Deadline for the Forward Capacity Auction in which it seeks to participate, the relevant capital costs to be entered into the capital budgeting model will be the undepreciated original capital costs adjusted for inflation. For any such resource, the prevailing market conditions will be those that were in place at the time of the decision to construct the resource.

(iv) Sufficient documentation and information must be included in the resource's qualification package to allow the Internal Market Monitor to make the determinations described in this subsection (b). Such documentation should include all relevant financial estimates and cost

projections for the project, including the project's pro-forma financing support data. For a New Import Capacity Resource, such documentation should also include the expected costs of purchasing power outside the New England Control Area (including transaction costs and supported by forward power price index values or a power price forecast for the applicable Capacity Commitment Period), expected transmission costs outside the New England Control Area, and expected transmission costs associated with importing to the New England Control Area, and may also include reasonable opportunity costs and risk adjustments. For a new capacity resource that has achieved commercial operation prior to the New Capacity Qualification Deadline, such documentation should also include all relevant financial data of actual incurred capital costs, actual operating costs, and actual revenues since the date of commercial operation. If the supporting documentation and information required by this subsection (b) is deficient, the Internal Market Monitor, at its sole discretion, may consult with the Project Sponsor to gather further information as necessary to complete its analysis. If after consultation, the Project Sponsor does not provide sufficient documentation and information for the Internal Market Monitor to complete its analysis, then the resource's New Resource Offer Floor Price shall be equal to the Offer Review Trigger Price.

(v) If the Internal Market Monitor determines that the requested offer prices are consistent with the Internal Market Monitor's capacity price estimate, then the resource's New Resource Offer Floor Price shall be equal to the requested offer price, subject to the provisions of subsection (vii) concerning New Import Capacity Resources.

(vi) If the Internal Market Monitor determines that the requested offer prices are not consistent with the Internal Market Monitor's capacity price estimate, then the resource's offer prices shall be set to a level that is consistent with the capacity price estimate, as determined by the Internal Market Monitor. Any such determination will be explained in the resource's qualification determination notification and will be filed with the Commission as part of the filing described in Section III.13.8.1(c), subject to the provisions of subsection (vii) concerning New Import Capacity Resources.

(vii) For New Import Capacity Resources that have been found to be associated with a pivotal supplier as determined pursuant to Section III.A.23, if the supplier elects to revise the requested offer prices pursuant to Section III.13.1.3.5.7 to values that are below the Internal Market

Monitor's capacity price estimate established pursuant to subsection (v) or (vi), then the resource's offer prices shall be equal to the revised offer prices.

(c) For a new capacity resource composed of assets having different technology types the Offer Review Trigger Price shall be the weighted average of the Offer Review Trigger Prices of the asset technology types of the assets that comprise the resource, based on the expected capacity contribution from each asset technology type. Sufficient documentation must be included in the resource's qualification package to permit the Internal Market Monitor to determine the weighted average Offer Review Trigger Price.

III.A.22. [Reserved.]

III.A.23. Pivotal Supplier Test for Existing Capacity Resources and New Import Capacity Resources in the Forward Capacity Market.

III.A.23.1. Pivotal Supplier Test.

The pivotal supplier test is performed prior to the commencement of the Forward Capacity Auction at the system level and for each import-constrained Capacity Zone.

An Existing Capacity Resource or New Import Capacity Resource is associated with a pivotal supplier if, after removing all the supplier's FCA Qualified Capacity, the ability to meet the relevant requirement is less than the requirement. Only those New Import Capacity Resources that are not (i) backed by a single new External Resource and associated with an investment in transmission that increases New England's import capability, or (ii) associated with an Elective Transmission Upgrade, are subject to the pivotal supplier test.

For the system level determination, the relevant requirement is the Installed Capacity Requirement (net of HQICCs). For each import-constrained Capacity Zone, the relevant requirement is the Local Sourcing Requirement for that import-constrained Capacity Zone.

At the system level, the ability to meet the relevant requirement is the sum of the following:

(a) The total FCA Qualified Capacity from all Existing Generating Capacity Resources and Existing Demand Capacity Resources in the Rest-of-Pool Capacity Zone;

(b) For each modeled import-constrained Capacity Zone, the greater of:

(1) the total FCA Qualified Capacity from all Existing Generating Capacity Resources and Existing Demand Capacity Resources within the import-constrained Capacity Zone plus, for each modeled external interface connected to the import-constrained Capacity Zone, the lesser of: (i) the capacity transfer limit of the interface (net of tie benefits), and; (ii) the total amount of FCA Qualified Capacity from Import Capacity Resources over the interface, and;

(2) the Local Sourcing Requirement of the import-constrained Capacity Zone;

(c) For each modeled nested export-constrained Capacity Zone, the lesser of:

(1) the total FCA Qualified Capacity from all Existing Generating Capacity Resources and Existing Demand Capacity Resources within the nested export-constrained Capacity Zone plus, for each external interface connected to the nested export-constrained Capacity Zone, the lesser of: (i) the capacity transfer limit of the interface (net of tie benefits), and; (ii) the total amount of FCA Qualified Capacity from Import Capacity Resources over the interface, and;

(2) the Maximum Capacity Limit of the nested export-constrained Capacity Zone;

(d) For each modeled export-constrained Capacity Zone that is not a nested export-constrained Capacity Zone, the lesser of:

(1) the total FCA Qualified Capacity from all Existing Generating Capacity Resources and Existing Demand Capacity Resources within the export-constrained Capacity Zone, excluding the total FCA Qualified Capacity from Existing Generating Capacity Resources and Existing Demand Capacity Resources within a nested export-constrained Capacity Zone, plus, for each external interface connected to the export-constrained Capacity Zone that is not included in any nested export-constrained Capacity Zone, the lesser of: (i) the capacity transfer limit of the interface (net of tie benefits), and; (ii) the total amount of FCA Qualified Capacity from Import Capacity Resources over the interface, excluding the contribution from any nested export-constrained Capacity Zone as determined pursuant to Section III.A.23.1(c), and;

(2) the Maximum Capacity Limit of the export-constrained Capacity Zone minus the contribution from any associated nested export-constrained Capacity Zone as determined pursuant to Section III.A.23.1(c), and;

(e) For each modeled external interface connected to the Rest-of-Pool Capacity Zone, the lesser of:

(1) the capacity transfer limit of the interface (net of tie benefits), and;

(2) the total amount of FCA Qualified Capacity from Import Capacity Resources over the interface.

For each import-constrained Capacity Zone, the ability to meet the relevant requirement is the sum of the following:

(1) The total FCA Qualified Capacity from all Existing Generating Capacity Resources and Existing Demand Capacity Resources located within the import-constrained Capacity Zone; and

(2) For each modeled external interface connected to the import-constrained Capacity Zone, the lesser of: (1) the capacity transfer limit of the interface (net of tie benefits), and; (2) the total amount of FCA Qualified Capacity from Import Capacity Resources over the interface.

III.A.23.2. Conditions Under Which Capacity is Treated as Non-Pivotal.

FCA Qualified Capacity of a supplier that is determined to be pivotal under Section III.A.23.1 is treated as non-pivotal under the following four conditions:

(a) If the removal of a supplier's FCA Qualified Capacity in an export-constrained Capacity Zone or nested export-constrained Capacity Zone does not change the quantity calculated in Section III.A.23.1(c) for that export-constrained Capacity Zone or nested export-constrained Capacity Zone, then that capacity is treated as capacity of a non-pivotal supplier.

(b) If the removal of a supplier's FCA Qualified Capacity in the form of Import Capacity Resources at an external interface does not change the quantity calculated in Section III.A.23.1(d) for that interface, then that capacity is treated as capacity of a non-pivotal supplier.

(c) If the removal of a supplier's FCA Qualified Capacity in the form of Import Capacity Resources at an external interface connected to an import-constrained Capacity Zone does not change the quantity calculated in Section III.A.23.1(f) for that interface, then that capacity is treated as capacity of a non-pivotal supplier.

(d) If a supplier whose only FCA Qualified Capacity is a single capacity resource with a bid that (i) is not subject to rationing under Section III.13.1.2.3.1 or III.13.2.6, and (ii) contains only one price-quantity pair for the entire FCA Qualified Capacity amount, then the capacity of that resource is treated as capacity of a non-pivotal supplier.

III.A.23.3. Pivotal Supplier Test Notification of Results.

Results of the pivotal supplier test will be made available to suppliers no later than seven days prior to the start of the Forward Capacity Auction.

III.A.23.4. Qualified Capacity for Purposes of Pivotal Supplier Test.

For purposes of the tests performed in Sections III.A.23.1 and III.A.23.2, the FCA Qualified Capacity of a supplier includes the capacity of Existing Generating Capacity Resources, Existing Demand Capacity Resources, Existing Import Capacity Resources, and New Import Capacity Resources (other than (i) a New Import Capacity Resource that is backed by a single new External Resource and that is associated with an investment in transmission that increases New England's import capability; and (ii) a New Import Capacity Resource associated with an Elective Transmission Upgrade) that is controlled by the supplier or its Affiliates.

For purposes of determining the ability to meet the relevant requirement under Section III.A.23.1, the FCA Qualified Capacity from New Import Capacity Resources does not include (i) any New Import Capacity Resource that is backed by a single new External Resource and that is associated with an investment in transmission that increases New England's import capability; and (ii) any New Import Capacity Resource associated with an Elective Transmission Upgrade.

For purposes of determining the FCA Qualified Capacity of a supplier or its Affiliates under Section III.A.23.4, "control" or "controlled" means the possession, directly or indirectly, of the authority to direct the decision-making regarding how capacity is offered into the Forward Capacity Market, and includes control by contract with unaffiliated third parties. In complying with Section I.3.5 of the ISO Tariff, a supplier shall inform the ISO of all capacity that it and its Affiliates control under this Section III.A.23.4 and all capacity the control of which it has contracted to a third party.

III.A.24. Retirement Portfolio Test for Existing Capacity Resources in the Forward Capacity Market.

The retirement portfolio test is performed prior to the commencement of the Forward Capacity Auction for each Lead Market Participant submitting a Permanent De-List Bid or Retirement De-List Bid. The test will be performed as follows:

If

i. The annual capacity revenue from the Lead Market Participant's total FCA Qualified Capacity, not including the FCA Qualified Capacity associated with the Permanent De-List Bid or Retirement De-List Bid, is greater than

ii. the annual capacity revenue from the Lead Market Participant's total FCA Qualified Capacity, including the FCA Qualified Capacity associated with the Permanent De-List Bid or Retirement De-List Bid, then

iii. the Lead Market Participant will be found to have a portfolio benefit pursuant to the retirement portfolio test.

Where,

iv. the Lead Market Participant's annual capacity revenue from the Lead Market Participant's total FCA Qualified Capacity not including the FCA Qualified Capacity associated with the Permanent De-List Bid or Retirement De-List Bid is calculated as the product of (a) the Lead Market Participant's total FCA Qualified Capacity not including the FCA Qualified Capacity associated with the Permanent De-List Bid or Retirement De-List Bid and (b) the Internal Market Monitor-estimated capacity clearing price not including the FCA Qualified Capacity associated with the Permanent De-List Bid or Retirement De-List Bid.

v. The Lead Market Participant's annual capacity revenue from the Lead Market Participant's total FCA Qualified Capacity including the FCA Qualified Capacity associated with the Permanent De-List Bid or Retirement De-List Bid is calculated as the product of (a) the Lead Market Participant's total FCA Qualified Capacity including the FCA Qualified Capacity associated with the Permanent De-List Bid or Retirement De-List Bid and (b) the Internal Market Monitor-estimated capacity clearing price including the FCA Qualified Capacity associated with the Permanent De-List Bid or Retirement De-List Bid.

vi. The Internal Market Monitor-estimated capacity clearing price, not to exceed the Forward Capacity Auction Starting Price, is based on the parameters of the System-Wide Capacity Demand Curve and Capacity Zone Demand Curves as specified in Section III.13.2.2.

For purposes of the test performed in this Section III.A.24, the FCA Qualified Capacity of a Lead Market Participant includes the capacity of Existing Capacity Resources that is controlled by the Lead Market Participant or its Affiliates.

For purposes of determining the FCA Qualified Capacity of a Lead Market Participant or its Affiliates under this Section III.A.24, “control” or “controlled” means the possession, directly or indirectly, of the authority to direct the decision-making regarding how capacity is offered into the Forward Capacity Market, and includes control by contract with unaffiliated third parties. In complying with Section I.3.5 of the ISO Tariff, a Lead Market Participant shall inform the ISO of all capacity that it and its Affiliates control under this Section III.A.4 and all capacity the control of which it has contracted to a third party.

APPENDIX K

INVENTORIED ENERGY PROGRAM

III.K Inventoried Energy Program

For the winter~~s~~ of 2023-2024~~ and 2024-2025~~ (the "relevant winter period"), the ISO shall administer an inventoried energy program in accordance with the provisions of this Appendix K.

III.K.1. Submission of Election Information

Participation in the inventoried energy program is voluntary. To participate in both the forward and spot components of the program, the information listed in this Section III.K.1 must be submitted to the ISO no later than the October 1 immediately preceding the start of the relevant winter ~~(a separate election submission must be made for each winter)~~ and must reflect an ability to provide the submitted inventoried energy throughout the relevant winter period. To participate in the spot component of the program only, the information listed in this Section III.K.1 may be submitted to the ISO through the end of the relevant winter period, in which case participation will begin (prospectively only) upon review and approval by the ISO of the information submitted.

(a) A list of the Market Participant's assets that will participate in the inventoried energy program, with a description for each such asset of: the Market Participant's Ownership Share in the asset; the types of fuel it can use; the approximate maximum amount of each fuel type that can be stored on site (and in upstream ponds) or, in the case of natural gas, the amount that is subject to a contract meeting the requirements described in Section III.K.1(a)(iii), as measured pursuant to the provisions of Section III.K.3.2.1.1(a); and a list of other assets at the same facility that share the fuel inventory (or, in the case of natural gas, a list of assets at the same or any other facility that can also take fuel pursuant to the same contract).

(i) The following asset types may not be included in a Market Participant's list of assets: Settlement Only Resources; assets not located in the New England Control Area; assets being compensated pursuant to a cost-of-service agreement (as described in Section III.13.2.5.2.5) during the relevant winter period; and assets that cannot operate on stored fuel (or natural gas subject to a contract as described in Section III.K.1(a)(iii)) at the ISO's direction.

(ii) A Demand Response Resource with Distributed Generation may be included in a Market Participant's list of assets.

(iii) For any asset listed that will participate in the inventoried energy program using natural gas as a fuel type, the Market Participant must also submit an executed contract for firm delivery of natural gas. Any such contract must include no limitations on when natural gas can be called during a day, and must specify the parties to the contract, the volume of gas to be delivered, the price to be paid for that gas, the pipeline delivery point name and gas meter number of the listed asset, terms related to pipeline transportation to the meter of the listed asset (with indication of whether the gas supplier or another entity is providing the transportation), and all other terms, conditions, or related agreements affecting whether and when gas will be delivered, the volume of gas to be delivered, and the price to be paid for that gas.

(b) A detailed description of how the Market Participant's energy inventory will be measured after each Inventoried Energy Day in accordance with the provisions of Section III.K.3.2.1.1 and converted to MWh (including the rates at which fuel is converted to energy for each asset). Where assets share fuel inventory, if the Market Participant believes that fuel should be allocated among those assets in a manner other than the default approach described in Section III.K.3.2.1.1(e)(ii), this description should explain and support that alternate allocation.

(c) Whether the Market Participant is electing to participate in only the spot component of the inventoried energy program or in both the forward and spot components.

(d) If electing to participate in both the forward and spot components of the program, the total MWh value for which the Market Participant elects to be compensated at the forward rate (the "Forward Energy Inventory Election"). This MWh value must be less than or equal to the combined MW output that the assets listed by the Market Participant (adjusted to account for Ownership Share) could provide over a period of 72 hours, as limited by the maximum amount of each fuel type that can be stored on site (and in upstream ponds) for each asset and as limited by the terms of any natural gas contracts submitted pursuant to Section III.K.1(a)(iii). If the Market Participant is submitting one or more contracts for natural gas, the Market Participant must indicate whether any of the suppliers listed in those contracts have the capability to deliver vaporized liquefied natural gas to New England, and if so, what portion of its Forward Energy Inventory Election, in MWh, should be attributed to liquefied natural gas (the "Forward LNG Inventory Election"). (For Market Participants electing to participate in only the spot component of the program, the Forward Energy Inventory Election and Forward LNG Inventory Election shall be zero.)

III.K.1.1 ISO Review and Approval of Election Information

The ISO will review each Market Participant's election submission, and may confer with the Market Participant to clarify or supplement the information provided. The ISO shall modify the amounts as necessary to ensure consistency with asset-specific operational characteristics, terms and conditions associated with submitted contracts, regulatory restrictions, and the requirements of the inventoried energy program. For election information that is submitted no later than October 1, the ISO will report the final program participation values to the Market Participant by the November 1 immediately preceding the start of the relevant winter, and participation will begin on December 1. For election information that is submitted after October 1 (spot component participation only), the ISO will, as soon as practicable, report the final program participation values and the date that participation will begin to the Market Participant.

(a) In performing this review, the ISO shall reject all or any portions of a contract for natural gas that:

(i) does not meet the requirements of Section III.K.1(a)(iii); or

(ii) requires (except in the case of an asset that is supplied from a liquefied natural gas facility adjacent and directly connected to the asset) the Market Participant to incur incremental costs to exercise the contract that may be greater than 250 percent of the average of the sum of the monthly Henry Hub natural gas futures prices and the Algonquin Citygates Basis natural gas futures prices for the December, January, and February of the relevant winter period on the earlier of the day the contract is executed and the first Business Day in October prior to that winter period.

(b) In performing this review, if the total of the Forward LNG Inventory Elections from all participating Market Participants (excluding amounts to be supplied to an asset from a liquefied natural gas facility adjacent and directly connected to the asset) exceeds 560,000 MWh, the ISO shall prorate each such Forward LNG Inventory Election such that the sum of such Forward LNG Inventory Elections is no greater than 560,000 MWh, and each Market Participant's Forward Energy Inventory Election shall be adjusted accordingly.

III.K.1.2 Posting of Forward Energy Inventory Election Amount

As soon as practicable after the November 1 immediately preceding the start of the relevant winter, the ISO will post to its website the total amount of Forward Energy Inventory Elections and Forward LNG Inventory Elections participating in the inventoried energy program for that winter.

III.K.2 Inventoried Energy Base Payments

A Market Participant participating in the forward and spot components of the inventoried energy program shall receive a base payment for each day of the months of December, January, and February. Each such base payment shall be equal to the Market Participant's Forward Energy Inventory Election (adjusted as described in Section III.K.1.1) multiplied by $82.49 per MWh and divided by the total number of days in those three months.

III.K.3 Inventoried Energy Spot Payments

A Market Participant participating in the spot component of the inventoried energy program (whether or not the Market Participant is also participating in the forward component of the program) shall receive a spot payment for each Inventoried Energy Day as calculated pursuant to this Section III.K.3.

III.K.3.1 Definition of Inventoried Energy Day

An Inventoried Energy Day shall exist for any Operating Day that occurs in the months of December, January, or February and for which the average of the high temperature and the low temperature on that Operating Day, as measured and reported by the National Weather Service at Bradley International Airport in Windsor Locks, Connecticut, is less than or equal to 17 degrees Fahrenheit.

III.K.3.2 Calculation of Inventoried Energy Spot Payment

A Market Participant's spot payment for an Inventoried Energy Day, which may be positive or negative, shall equal the Market Participant's Real-Time Energy Inventory minus its Forward Energy Inventory Election, with the difference multiplied by $8.25 per MWh.

III.K.3.2.1 Calculation of Real-Time Energy Inventory

A Market Participant's Real-Time Energy Inventory for an Inventoried Energy Day shall be the sum of the Real-Time Energy Inventories for each of the Market Participant's assets participating in the program (adjusted as described in Section III.K.3.2.1.2); provided, however, that where more than one Market Participant has an Ownership Share in an asset, the asset's Real-Time Energy Inventory will be apportioned based on each Market Participant's Ownership Share.

III.K.3.2.1.1 Asset-Level Real-Time Energy Inventory

Each asset's Real-Time Energy Inventory will be determined as follows:

(a) The Market Participant must measure and report to the ISO the Real-Time Energy Inventory for each of the assets participating in the program between 7:00 a.m. and 8:00 a.m. on the Operating Day immediately following each Inventoried Energy Day. The Real-Time Energy Inventory must be reported to the ISO both in MWh and in units appropriate to the fuel type and measured in accordance with the following provisions:

(i) Oil. The Real-Time Energy Inventory of an asset that runs on oil shall be the number of dedicated barrels of oil stored in an in-service tank (located on site or at an adjacent location with direct pipeline transfer capability to the asset), excluding any amount that is unobtainable or unusable (due to priming requirements, sediment, volume below the suction line, or any other reason).

(ii) Coal. The Real-Time Energy Inventory of an asset that runs on coal shall be the number of metric tons of coal stored on site, excluding any amount that is unobtainable or unusable for any reason.

(iii) Nuclear. The Real-Time Energy Inventory of a nuclear asset shall be the number of days until the asset's next scheduled refueling outage.

(iv) Natural Gas. The Real-Time Energy Inventory for an asset that runs on natural gas shall be the amount of natural gas available to the asset pursuant to the terms of the relevant contracts submitted pursuant to Section III.K.1(a)(iii), adjusted to reflect any limitation that the suppliers listed in the contracts may have on the capability to deliver natural gas. The Market Participant must specify what portion of the asset's Real-Time Energy Inventory, in MWh, is associated with liquefied natural gas.

(v) Pumped Hydro. The Real-Time Energy Inventory of a pumped storage asset shall be the amount of water (in gallons or by elevation, consistent with the description provided by the Market Participant pursuant to Section III.K.1(b)) in the on-site reservoir that is available for generation, excluding any amount that is unobtainable or unusable for any reason.

(vi) Pondage. The Real-Time Energy Inventory of an asset with pondage shall be the amount of water (in gallons or by elevation, consistent with the description provided by the Market Participant pursuant to Section III.K.1(b)) in on-site and upstream ponds controlled by the Market Participant with a transit time to the asset of no more than 12 hours, excluding any amount that is unobtainable or unusable for any reason.

(vii) Biomass/Refuse. The Real-Time Energy Inventory of an asset that runs on biomass or refuse shall be the number of metric tons of the relevant material stored on site, excluding any amount that is unobtainable or unusable for any reason.

(viii) Electric Storage Facility. The Real-Time Energy Inventory of an Electric Storage Facility shall be its available energy in MWh.

(b) If the Market Participant fails to measure or report the energy inventory or fuel amounts for an asset as required, that asset's Real-Time Energy Inventory for the Inventoried Energy Day shall be zero.

(c) The Market Participant must limit each asset's Real-Time Energy Inventory as appropriate to respect federal and state restrictions on the use of the fuel (such as water flow or emissions limitations).

(d) The reported amounts are subject to verification by the ISO. As part of any such verification, the ISO may request additional information or documentation from a Market Participant, or may require a certificate signed by a Senior Officer of the Market Participant attesting that the reported amount of fuel is available to the Market Participant as required by the provisions of the inventoried energy program.

(e) In determining final Real-Time Energy Inventory amounts for each asset, the ISO will:

(i) adjust the reported amounts consistent with the results of any verification performed pursuant to Section III.K.3.2.1.1(d);

(ii) allocate shared fuel inventory among the relevant assets in a manner that maximizes its use based on the efficiency with which the assets convert fuel to energy (unless

information submitted pursuant to Section III.K.1(b) supports a different allocation) and that is consistent with any applicable contract provisions (in the case of natural gas) and maximum daily production limits of the assets sharing fuel inventory; and

(iii) limit each asset's Real-Time Energy Inventory to the asset's average available outage-adjusted output on the Inventoried Energy Day for a maximum duration of 72 hours.

III.K.3.2.1.2 Proration of Liquefied Natural Gas

If the total amount of Real-Time Energy Inventory associated with liquefied natural gas (excluding amounts to be supplied to an asset from a liquefied natural gas facility adjacent and directly connected to the asset) exceeds 560,000 MWh, then the ISO shall prorate such Real-Time Energy Inventory associated with liquefied natural gas as follows:

(a) any Real-Time Energy Inventory associated with liquefied natural gas that corresponds to a Market Participant's Forward LNG Inventory Election (prorated as described in Section III.K.1.1(b)) shall be counted without reduction; and

(b) any Real-Time Energy Inventory associated with liquefied natural gas that does not correspond to a Market Participant's Forward LNG Inventory Election (prorated as described in Section III.K.1.1(b)) shall be prorated such that the sum of the Real-Time Energy Inventory associated with liquefied natural gas (including the amount described in Section III.K.3.2.1.2(a)) does not exceed 560,000 MWh.

III.K.4 Cost Allocation

Costs associated with the inventoried energy program shall be allocated on a regional basis to Real-Time Load Obligation, excluding Real-Time Load Obligation associated with Storage DARDs and Real-Time Load Obligation associated with Coordinated External Transactions. Costs associated with base payments shall be allocated across all days of the months of December, January, and February; costs associated with spot payments shall be allocated to the relevant Inventoried Energy Day.

SECTION III

MARKET RULE 1

APPENDIX L

ISO NEW ENGLAND FUEL SECURITY RELIABILITY REVIEW STANDARD

As described in Section III.13.2.5.2.5A, a fuel security reliability review will be performed for certain submissions by Existing Generating Capacity Resources. This Appendix establishes the reliability trigger for that fuel security reliability review. This Appendix L will remain in effect for the 2022/23~~,~~ and 2023/24 ~~and 2024/25~~ Capacity Commitment Periods, after which this Appendix L will sunset.

The fuel security model used for reliability reviews shall consist of an hour-by-hour chronological simulation of the electric supply for the winter period from the beginning of December through the end of February. As applied to the fuel security reliability review model established pursuant to Appendix I of Planning Procedure No. 10, observation of either of the following will result in the generator being tested having its (i) Retirement De-List Bids, (ii) substitution auction demand bids, and (iii) certain bilateral transactions and reconfiguration auction demand bid offers rejected for reliability reasons:

(i) The retirement will result in the depletion of 10-minute reserves below 700 MW in any hour in the absence of a contingency in more than one liquefied natural gas supply scenario case or,

(ii) the use of load shedding in any hour pursuant to Operating Procedure No. 7.

Attachment D-2

ISO Clean Tariff

I.2 Rules of Construction; Definitions

I.2.1. Rules of Construction:

In this Tariff, unless otherwise provided herein:

(a) words denoting the singular include the plural and vice versa;

(b) words denoting a gender include all genders;

(c) references to a particular part, clause, section, paragraph, article, exhibit, schedule, appendix or other attachment shall be a reference to a part, clause, section, paragraph, or article of, or an exhibit, schedule, appendix or other attachment to, this Tariff;

(d) the exhibits, schedules and appendices attached hereto are incorporated herein by reference and shall be construed with an as an integral part of this Tariff to the same extent as if they were set forth verbatim herein;

(e) a reference to any statute, regulation, proclamation, ordinance or law includes all statutes, regulations, proclamations, amendments, ordinances or laws varying, consolidating or replacing the same from time to time, and a reference to a statute includes all regulations, policies, protocols, codes, proclamations and ordinances issued or otherwise applicable under that statute unless, in any such case, otherwise expressly provided in any such statute or in this Tariff;

(f) a reference to a particular section, paragraph or other part of a particular statute shall be deemed to be a reference to any other section, paragraph or other part substituted therefor from time to time;

(g) a definition of or reference to any document, instrument or agreement includes any amendment or supplement to, or restatement, replacement, modification or novation of, any such document, instrument or agreement unless otherwise specified in such definition or in the context in which such reference is used;

(h) a reference to any person (as hereinafter defined) includes such person's successors and permitted assigns in that designated capacity;

(i) any reference to "days" shall mean calendar days unless "Business Days" (as hereinafter defined) are expressly specified;

(j) if the date as of which any right, option or election is exercisable, or the date upon which any amount is due and payable, is stated to be on a date or day that is not a Business Day, such right, option or election may be exercised, and such amount shall be deemed due and payable, on the next succeeding Business Day with the same effect as if the same was exercised or made on such date or day (without, in the case of any such payment, the payment or accrual of any interest or

other late payment or charge, provided such payment is made on such next succeeding Business Day);

(k) words such as "hereunder," "hereto," "hereof" and "herein" and other words of similar import shall, unless the context requires otherwise, refer to this Tariff as a whole and not to any particular article, section, subsection, paragraph or clause hereof; and a reference to "include" or "including" means including without limiting the generality of any description preceding such term, and for purposes hereof the rule of *ejusdem generis* shall not be applicable to limit a general statement, followed by or referable to an enumeration of specific matters, to matters similar to those specifically mentioned.

I.2.2. Definitions:

In this Tariff, the terms listed in this section shall be defined as described below:

Active Demand Capacity Resource is one or more Demand Response Resources located within the same Dispatch Zone, that is registered with the ISO, assigned a unique resource identification number by the ISO, and participates in the Forward Capacity Market to fulfill a Market Participant's Capacity Supply Obligation pursuant to Section III.13 of Market Rule 1.

Actual Capacity Provided is the measure of capacity provided during a Capacity Scarcity Condition, as described in Section III.13.7.2.2 of Market Rule 1.

Actual Load is the consumption at the Retail Delivery Point for the hour.

Additional Resource Blackstart O&M Payment is defined and calculated as specified in Section 5.1.2 of Schedule 16 to the OATT.

Additional Resource Specified-Term Blackstart Capital Payment is defined and calculated as specified in Section 5.1.2 of Schedule 16 to the OATT.

Additional Resource Standard Blackstart Capital Payment is defined and calculated as specified in Section 5.1.2 of Schedule 16 to the OATT.

Administrative Costs are those costs incurred in connection with the review of Applications for transmission service and the carrying out of System Impact Studies and Facilities Studies.

Administrative Export De-List Bid is a bid that may be submitted in a Forward Capacity Auction by certain Existing Generating Capacity Resources subject to a multi-year contract to sell capacity outside of the New England Control Area during the associated Capacity Commitment Period, as described in Section III.13.1.2.3.1.4 of Market Rule 1.

Administrative Sanctions are defined in Section III.B.4.1.2 of Appendix B of Market Rule 1.

ADR Neutrals are one or more firms or individuals identified by the ISO with the advice and consent of the Participants Committee that are prepared to act as neutrals in ADR proceedings under Appendix D to Market Rule 1.

Advance is defined in Section IV.A.3.2 of the Tariff.

Affected Party, for purposes of the ISO New England Billing Policy, is defined in Section 6.3.5 of the ISO New England Billing Policy.

Affiliate is any person or entity that controls, is controlled by, or is under common control by another person or entity. For purposes of this definition, "control" means the possession, directly or indirectly, of the authority to direct the management or policies of an entity. A voting interest of ten percent or more shall create a rebuttable presumption of control.

AGC is automatic generation control.

AGC SetPoint is the desired output signal for a Resource providing Regulation that is produced by the AGC system as frequently as every four seconds.

AGC SetPoint Deadband is a deadband expressed in megawatts that is applied to changing values of the AGC SetPoint for generating units.

Allocated Assessment is a Covered Entity's right to seek and obtain payment and recovery of its share in any shortfall payments under Section 3.3 or Section 3.4 of the ISO New England Billing Policy.

Alternative Dispute Resolution (ADR) is the procedure set forth in Appendix D to Market Rule 1.

Alternative Technology Regulation Resource (ATRR) is one or more facilities capable of providing Regulation that have been registered in accordance with the Asset Registration Process. An Alternative Technology Regulation Resource is eligible to participate in the Regulation Market.

Ancillary Services are those services that are necessary to support the transmission of electric capacity and energy from resources to loads while maintaining reliable operation of the New England Transmission System in accordance with Good Utility Practice.

Announced Schedule 1 EA Amount, Announced Schedule 2 EA Amount, Announced Schedule 3 EA Amount are defined in Section IV.B.2.2 of the Tariff.

Annual Transmission Revenue Requirements are the annual revenue requirements of a PTO's PTF or of all PTOs' PTF for purposes of the OATT shall be the amount determined in accordance with Attachment F to the OATT.

Annual Reconfiguration Transaction is a bilateral transaction that may be used in accordance with Section III.13.5.4 of Market Rule 1 to specify a price when a Capacity Supply Obligation is transferred using supply offers and demand bids in Annual Reconfiguration Auctions.

Applicants, for the purposes of the ISO New England Financial Assurance Policy, are entities applying for Market Participant status or for transmission service from the ISO.

Application is a written request by an Eligible Customer for transmission service pursuant to the provisions of the OATT.

Asset is a Generator Asset, a Demand Response Asset, a component of an On-Peak Demand Resource or Seasonal Peak Demand Resource, a Load Asset (including an Asset Related Demand), an Alternative Technology Regulation Resource, or a Tie-Line Asset.

Asset Registration Process is the ISO business process for registering an Asset.

Asset Related Demand is a Load Asset that has been discretely modeled within the ISO's dispatch and settlement systems, settles at a Node, has been registered in accordance with the Asset Registration

Process, and is made up of either: (1) one or more individual end-use metered customers receiving service from the same point or points of electrical supply with an aggregate average hourly load of 1 MW or greater during the 12 months preceding its registration; (2) a Storage DARD with a consumption capability of at least 0.1 MW; or (3) one or more storage facilities that are not Electric Storage Facilities with an aggregate consumption capability of at least 1 MW.

Asset Related Demand Bid Block-Hours are Block-Hours assigned to the Lead Market Participant for each Asset Related Demand bid. Blocks of the bid in effect for each hour will be totaled to determine the daily quantity of Asset Related Demand Bid Block-Hours. In the case that a Resource has a Real-Time unit status of "unavailable" for an entire day, that day will not contribute to the quantity of Asset Related Demand Bid Block-Hours. However, if the Resource has at least one hour of the day with a unit status of "available," the entire day will contribute to the quantity of Asset Related Demand Bid Block-Hours.

Asset-Specific Going Forward Costs are the net costs of an asset that is part of an Existing Generating Capacity Resource, calculated for the asset in the same manner as the net costs of Existing Generating Capacity Resources as described in Section III.13.1.2.3.2.1.1.1 (for an asset with a Static De-List Bid or an Export Bid) or Section III.13.1.2.3.2.1.1.2 (for an asset with a Permanent De-List Bid or Retirement De-List Bid).

Assigned Meter Reader reports to the ISO the hourly and monthly MWh associated with the Asset. These MWh are used for settlement. The Assigned Meter Reader may designate an agent to help fulfill its Assigned Meter Reader responsibilities; however, the Assigned Meter Reader remains functionally responsible to the ISO.

Auction Revenue Right (ARR) is a right to receive FTR Auction Revenues in accordance with Appendix C of Market Rule 1.

Auction Revenue Right Allocation (ARR Allocation) is defined in Section 1 of Appendix C of Market Rule 1.

Auction Revenue Right Holder (ARR Holder) is an entity which is the record holder of an Auction Revenue Right (excluding an Incremental ARR) in the register maintained by the ISO.

Authorized Commission is defined in Section 3.3 of the ISO New England Information Policy.

Authorized Person is defined in Section 3.3 of the ISO New England Information Policy.

Automatic Response Rate is the response rate, in MW/Minute, at which a Market Participant is willing to have a Regulation Resource change its output or consumption while providing Regulation between the Regulation High Limit and Regulation Low Limit.

Available Energy is a value that reflects the MWhs of energy available from an Electric Storage Facility for economic dispatch.

Available Storage is a value that reflects the MWhs of unused storage available from an Electric Storage Facility for economic dispatch of consumption.

Average Hourly Load Reduction is either: (i) the sum of the On-Peak Demand Resource's electrical energy reduction during Demand Resource On-Peak Hours in the month divided by the number of Demand Resource On-Peak Hours in the month; or (ii) the sum of the Seasonal Peak Demand Resource's electrical energy reduction during Demand Resource Seasonal Peak Hours in the month divided by the number of Demand Resource Seasonal Peak Hours in the month. The On-Peak Demand Resource's or Seasonal Peak Demand Resource's electrical energy reduction and Average Hourly Load Reduction shall be determined consistent with the resource's Measurement and Verification Plan, which shall be reviewed by the ISO to ensure consistency with the measurement and verification requirements, as described in Section III.13.1.4.3 of Market Rule 1 and the ISO New England Manuals.

Average Hourly Output is either: (i) the sum of the On-Peak Demand Resource's electrical energy output during Demand Resource On-Peak Hours in the month divided by the number of Demand Resource On-Peak Hours in the month; or (ii) the sum of the Seasonal Peak Demand Resource's electrical energy output during Demand Resource Seasonal Peak Hours in the month divided by the number of Demand Resource Seasonal Peak Hours in the month. Electrical energy output and Average Hourly Output shall be determined consistent with the resource's Measurement and Verification Plan, which shall be reviewed by the ISO to ensure consistency with the measurement and verification requirements, as described in Section III.13.1.4.3 of Market Rule 1 and the ISO New England Manuals.

Average Monthly PER is calculated in accordance with Section III.13.7.1.2.2 of Market Rule 1.

Backstop Transmission Solution is a solution proposed: (i) to address a reliability or market efficiency need identified by the ISO in a Needs Assessment reported by the ISO pursuant to Section 4.1(i) of Attachment K to the ISO OATT, (ii) by the PTO or PTOs with an obligation under Schedule 3.09(a) of the TOA to address the identified need; and (iii) in circumstances in which the competitive solution process specified in Section 4.3 of Attachment K to the ISO OATT will be utilized.

Bankruptcy Code is the United States Bankruptcy Code.

Bankruptcy Event occurs when a Covered Entity files a voluntary or involuntary petition in bankruptcy or commences a proceeding under the United States Bankruptcy Code or any other applicable law concerning insolvency, reorganization or bankruptcy by or against such Covered Entity as debtor.

Bilateral Contract (BC) is any of the following types of contracts: Internal Bilateral for Load, Internal Bilateral for Market for Energy, and External Transactions.

Bilateral Contract Block-Hours are Block-Hours assigned to the seller and purchaser of an Internal Bilateral for Load, Internal Bilateral for Market for Energy and External Transactions; provided, however, that only those contracts which apply to the Real-Time Energy Market will accrue Block-Hours.

Binary Storage DARD is a DARD that participates in the New England Markets as part of a Binary Storage Facility, as described in Section III.1.10.6 of Market Rule 1.

Binary Storage Facility is a type of Electric Storage Facility, as described in Section III.1.10.6 of Market Rule 1.

Blackstart Capability Test is the test, required by ISO New England Operating Documents, of a resource's capability to provide Blackstart Service.

Blackstart Capital Payment is the annual compensation, as calculated pursuant to Section 5.1, or as referred to in Section 5.2, of Schedule 16 to the OATT, for a Designated Blackstart Resource's Blackstart Equipment capital costs associated with the provision of Blackstart Service (excluding the capital costs associated with compliance with NERC Critical Infrastructure Protection Reliability Standards as part of Blackstart Service).

Blackstart Equipment is any equipment that is solely necessary to enable the Designated Blackstart Resource to provide Blackstart Service and is not required to provide other products or services under the Tariff.

Blackstart O&M Payment is the annual Blackstart O&M compensation calculated under either Section 5.1 or 5.2 of Schedule 16 of the OATT, as applicable.

Blackstart Owner is the Market Participant who is authorized on behalf of the Generator Owner(s) to offer or operate the resource as a Designated Blackstart Resource and is authorized to commit the resource to provide Blackstart Service.

Blackstart Service is the Ancillary Service described in Section II.47 of the Tariff and Schedule 16 of the OATT.

Blackstart Service Commitment is the commitment by a Blackstart Owner for its resource to provide Blackstart Service and the acceptance of that commitment by the ISO, in the manner detailed in ISO New England Operating Procedure No. 11 – Designated Blackstart Resource Administration (OP 11), and which includes a commitment to provide Blackstart Service established under Operating Procedure 11 – Designated Blackstart Resource Administration (OP11).

Blackstart Service Minimum Criteria are the minimum criteria that a Blackstart Owner and its resource must meet in order to establish and maintain a resource as a Designated Blackstart Resource.

Blackstart Standard Rate Payment is the formulaic rate of monthly compensation, as calculated pursuant to Section 5 of Schedule 16 to the OATT, paid to a Blackstart Owner for the provision of Blackstart Service from a Designated Blackstart Resource.

Blackstart Station is comprised of (i) a single Designated Blackstart Resource or (ii) two or more Designated Blackstart Resources that share Blackstart Equipment.

Blackstart Station-specific Rate Payment is the Commission-approved compensation, as calculated pursuant to Section 5.2 of Schedule 16 to the OATT, paid to a Blackstart Owner on a monthly basis for the provision of Blackstart Service by Designated Blackstart Resources located at a specific Blackstart Station.

Blackstart Station-specific Rate Capital Payment is a component of the Blackstart Station-specific Rate Payment that reflects a Blackstart Station's capital Blackstart Equipment costs associated with the provision of Blackstart Service (excluding the capital costs associated with compliance with NERC Critical Infrastructure Protection Reliability Standards as part of Blackstart Service).

Block is defined as follows: (1) With respect to Bilateral Contracts, a Bilateral Contract administered by the ISO for an hour; (2) with respect to Supply Offers administered by the ISO, a quantity with a related price for Energy (Supply Offers for Energy may contain multiple sets of quantity and price pairs for each hour); (3) with respect to Demand Bids administered by the ISO, a quantity with a related price for Energy (Demand Bids for Energy may contain multiple sets of quantity and price pairs for each hour); (4) with respect to Increment Offers administered by the ISO, a quantity with a related price for Energy (Increment Offers for Energy may contain multiple sets of quantity and price pairs for each hour); (5) with respect to Decrement Bids administered by the ISO, a quantity with a related price for Energy (Decrement Bids for Energy may contain multiple sets of quantity and price pairs for each hour); (6) with respect to Asset Related Demand bids administered by the ISO, a quantity with a related price for Energy (Asset Related Demand bids may contain multiple sets of quantity and price pairs for each hour); and (7) with respect to Demand Reduction Offers administered by the ISO, a quantity of reduced demand with a related price (Demand Reduction Offers may contain multiple sets of quantity and price pairs for the day).

Block-Hours are the number of Blocks administered for a particular hour.

Budget and Finance Subcommittee is a subcommittee of the Participants Committee, the responsibilities of which are specified in Section 8.4 of the Participants Agreement.

Business Day is any day other than a Saturday or Sunday or ISO holidays as posted by the ISO on its website.

Cancelled Start NCPC Credit is an NCPC Credit calculated pursuant to Appendix F to Market Rule 1.

Capability Demonstration Year is the one year period from September 1 through August 31.

Capacity Acquiring Resource is a resource that is seeking to acquire a Capacity Supply Obligation through: (1) a Capacity Supply Obligation Bilateral, as described in Section III.13.5.1, or; (2) an annual or monthly reconfiguration auction, as described in Section III.13.4.

Capacity Balancing Ratio is a ratio used in calculating the Capacity Performance Payment in the Forward Capacity Market, as described in Section III.13.7.2.3 of Market Rule 1.

Capacity Base Payment is the portion of revenue received in the Forward Capacity Market as described in Section III.13.7.1 of Market Rule 1.

Capacity Capability Interconnection Standard has the meaning specified in Schedule 22, Schedule 23, and Schedule 25 of the OATT.

Capacity Clearing Price is the clearing price for a Capacity Zone for a Capacity Commitment Period resulting from the Forward Capacity Auction conducted for that Capacity Commitment Period, as determined in accordance with Section III.13.2.7 of Market Rule 1.

Capacity Commitment Period is the one-year period from June 1 through May 31 for which obligations are assumed and payments are made in the Forward Capacity Market.

Capacity Cost (CC) is one of four forms of compensation that may be paid to resources providing VAR Service under Schedule 2 of the OATT.

Capacity Export Through Import Constrained Zone Transaction is defined in Section III.1.10.7(f)(i) of Market Rule 1.

Capacity Load Obligation is the quantity of capacity for which a Market Participant is financially responsible as described in Section III.13.7.5.2 of Market Rule 1.

Capacity Load Obligation Acquiring Participant is a load serving entity or any other Market Participant seeking to acquire a Capacity Load Obligation through a Capacity Load Obligation Bilateral, as described in Section III.13.5.2 of Market Rule 1.

Capacity Network Import Capability (CNI Capability) is as defined in Section I of Schedule 25 of the OATT.

Capacity Network Import Interconnection Service (CNI Interconnection Service) is as defined in Section I of Schedule 25 of the OATT.

Capacity Load Obligation Bilateral is a bilateral contract through which a Market Participant may transfer all or a portion of its Capacity Load Obligation to another entity, as described in Section III.13.5 of Market Rule 1.

Capacity Load Obligation Transferring Participant is an entity that has a Capacity Load Obligation and is seeking to shed such obligation through a Capacity Load Obligation Bilateral, as described in Section III.13.5.2 of Market Rule 1.

Capacity Network Resource (CNR) is defined in Section I of Schedule 22 and Attachment 1 to Schedule 23 of the OATT.

Capacity Network Resource Interconnection Service (CNR Interconnection Service) is defined in Section I of Schedule 22 and Attachment 1 to Schedule 23 of the OATT.

Capacity Performance Bilateral is a transaction for transferring Capacity Performance Score, as described in Section III.13.5.3 of Market Rule 1.

Capacity Performance Payment is the performance-dependent portion of revenue received in the Forward Capacity Market, as described in Section III.13.7.2 of Market Rule 1.

Capacity Performance Payment Rate is a rate used in calculating Capacity Performance Payments, as described in Section III.13.7.2.5 of Market Rule 1.

Capacity Performance Score is a figure used in determining Capacity Performance Payments, as described in Section III.13.7.2.4 of Market Rule 1.

Capacity Rationing Rule addresses whether offers and bids in a Forward Capacity Auction may be rationed, as described in Section III.13.2.6 of Market Rule 1.

Capacity Scarcity Condition is a period during which performance is measured in the Forward Capacity Market, as described in Section III.13.7.2.1 of Market Rule 1.

Capacity Scarcity Condition is a period during which performance is measured in the Forward Capacity Market, as described in Section III.13.7.2.1 of Market Rule 1.

Capacity Supply Obligation is an obligation to provide capacity from a resource, or a portion thereof, to satisfy a portion of the Installed Capacity Requirement that is acquired through a Forward Capacity Auction in accordance with Section III.13.2, a reconfiguration auction in accordance with Section III.13.4, or a Capacity Supply Obligation Bilateral in accordance with Section III.13.5.1 of Market Rule 1.

Capacity Supply Obligation Bilateral is a bilateral contract through which a Market Participant may transfer all or a part of its Capacity Supply Obligation to another entity, as described in Section III.13.5.1 of Market Rule 1.

Capacity Transfer Rights (CTRs) are calculated in accordance with Section III.13.7.5.4.

Capacity Transferring Resource is a resource that has a Capacity Supply Obligation and is seeking to shed such obligation, or a portion thereof, through: (1) a Capacity Supply Obligation Bilateral, as described in Section III.13.5.1, or; (2) an annual or monthly reconfiguration auction, as described in Section III.13.4.

Capacity Zone is a geographic sub-region of the New England Control Area as determined in accordance with Section III.12.4 of Market Rule 1.

Capacity Zone Demand Curves are the demand curves used in the Forward Capacity Market for a Capacity Zone as specified in Sections III.13.2.2.2 and III.13.2.2.3.

Capital Funding Charge (CFC) is defined in Section IV.B.2 of the Tariff.

CARL Data is Control Area reliability data submitted to the ISO to permit an assessment of the ability of an external Control Area to provide energy to the New England Control Area in support of capacity offered to the New England Control Area by that external Control Area.

Category B Designated Blackstart Resource has the same meaning as Designated Blackstart Resource.

Charge is a sum of money due from a Covered Entity to the ISO, either in its individual capacity or as billing and collection agent for NEPOOL pursuant to the Participants Agreement.

CLAIM10 is the value, expressed in megawatts, calculated pursuant to Section III.9.5.3 of the Tariff.

CLAIM30 is the value, expressed in megawatts, calculated pursuant to Section III.9.5.3 of the Tariff.

Claimed Capability Audit is performed to determine the real power output capability of a Generator Asset or the demand reduction capability of a Demand Response Resource.

Cluster Enabling Transmission Upgrade (CETU) has the meaning specified in Section I of Schedule 22, Attachment 1 to Schedule 23, and Section I of Schedule 25 of the OATT.

Cluster Enabling Transmission Upgrade Regional Planning Study (CRPS) has the meaning specified in Section I of Schedule 22, Attachment 1 to Schedule 23, and Section I of Schedule 25 of the OATT.

Cluster Entry Deadline has the meaning specified in Section I of Schedule 22, Attachment 1 to Schedule 23, and Section I of Schedule 25 of the OATT.

Cluster Interconnection System Impact Study (CSIS) has the meaning specified in Section I of Schedule 22, Attachment 1 to Schedule 23, and Section I of Schedule 25 of the OATT.

Clustering has the meaning specified in Section I of Schedule 22, Attachment 1 to Schedule 23, and Section I of Schedule 25 of the OATT.

CNR Capability is defined in Section I of Schedule 22 and Attachment 1 to Schedule 23 of the OATT.

Coincident Peak Contribution is a Market Participant's share of the New England Control Area coincident peak demand for the prior calendar year as determined prior to the start of each Capacity Commitment Period, which reflects the sum of the prior year's annual coincident peak contributions of the customers served by the Market Participant at each Load Asset. Daily Coincident Peak Contribution

values shall be submitted by the Assigned Meter Reader or Host Participant by the meter reading deadline to the ISO.

Commercial Capacity is capacity that has achieved FCM Commercial Operation.

Commission is the Federal Energy Regulatory Commission.

Commitment Period is (i) for a Day-Ahead Energy Market commitment, a period of one or more contiguous hours for which a Resource is cleared in the Day-Ahead Energy Market, and (ii) for a Real-Time Energy Market commitment, the period of time for which the ISO indicates the Resource is being committed when it issues the Dispatch Instruction. If the ISO does not indicate the period of time for which the Resource is being committed in the Real-Time Energy Market, then the Commitment Period is the Minimum Run Time for an offline Resource and one hour for an online Resource.

Common Costs are those costs associated with a Station that are avoided only by the clearing of the Static De-List Bids, the Permanent De-List Bids, or the Retirement De-List Bids of all the Existing Generating Capacity Resources comprising the Station.

Completed Application is an Application that satisfies all of the information and other requirements of the OATT, including any required deposit.

Compliance Effective Date is the date upon which the changes in the predecessor NEPOOL Open Access Transmission Tariff which have been reflected herein to comply with the Commission's Order of April 20, 1998 became effective.

Composite FCM Transaction is a transaction for separate resources seeking to participate as a single composite resource in a Forward Capacity Auction in which multiple Designated FCM Participants provide capacity, as described in Section III.13.1.5 of Market Rule 1.

Conditional Qualified New Resource is defined in Section III.13.1.1.2.3(f) of Market Rule 1.

Confidential Information is defined in Section 2.1 of the ISO New England Information Policy, which is Attachment D to the Tariff.

Confidentiality Agreement is Attachment 1 to the ISO New England Billing Policy.

Congestion is a condition of the New England Transmission System in which transmission limitations prevent unconstrained regional economic dispatch of the power system. Congestion is the condition that results in the Congestion Component of the Locational Marginal Price at one Location being different from the Congestion Component of the Locational Marginal Price at another Location during any given hour of the dispatch day in the Day-Ahead Energy Market or Real-Time Energy Market.

Congestion Component is the component of the nodal price that reflects the marginal cost of congestion at a given Node or External Node relative to the reference point. When used in connection with Zonal Price and Hub Price, the term Congestion Component refers to the Congestion Components of the nodal prices that comprise the Zonal Price and Hub Price weighted and averaged in the same way that nodal prices are weighted to determine Zonal Price and averaged to determine the Hub Price.

Congestion Cost is the cost of congestion as measured by the difference between the Congestion Components of the Locational Marginal Prices at different Locations and/or Reliability Regions on the New England Transmission System.

Congestion Paying LSE is, for the purpose of the allocation of FTR Auction Revenues to ARR Holders as provided for in Appendix C of Market Rule 1, a Market Participant or Non-Market Participant Transmission Customer that is responsible for paying for Congestion Costs as a Transmission Customer paying for Regional Network Service under the Transmission, Markets and Services Tariff, unless such Transmission Customer has transferred its obligation to supply load in accordance with ISO New England System Rules, in which case the Congestion Paying LSE shall be the Market Participant supplying the transferred load obligation. The term Congestion Paying LSE shall be deemed to include, but not be limited to, the seller of internal bilateral transactions that transfer Real-Time Load Obligations under the ISO New England System Rules.

Congestion Revenue Fund is the amount available for payment of target allocations to FTR Holders from the collection of Congestion Cost.

Congestion Shortfall means congestion payments exceed congestion charges during the billing process in any billing period.

Contingency Reserve has the meaning specified in the Glossary of Terms Used in NERC Reliability Standards.

Contingency Reserve Restoration Period has the meaning specified in the Glossary of Terms Used in NERC Reliability Standards.

Continuous Storage ATRR is an ATRR that participates in the New England Markets as part of a Continuous Storage Facility, as described in Section III.1.10.6 of Market Rule 1.

Continuous Storage DARD is a DARD that participates in the New England Markets as part of a Continuous Storage Facility, as described in Section III.1.10.6 of Market Rule 1.

Continuous Storage Generator Asset is a Generator Asset that participates in the New England Markets as part of a Continuous Storage Facility, as described in Section III.1.10.6 of Market Rule 1.

Continuous Storage Facility is a type of Electric Storage Facility, as described in Section III.1.10.6 of Market Rule 1.

Control Agreement is the document posted on the ISO website that is required if a Market Participant's cash collateral is to be invested in BlackRock funds.

Control Area is an electric power system or combination of electric power systems to which a common automatic generation control scheme is applied in order to:

(1) match, at all times, the power output of the generators within the electric power system(s) and capacity and energy purchased from entities outside the electric power system(s), with the load within the electric power system(s);

(2) maintain scheduled interchange with other Control Areas, within the limits of Good Utility Practice;

(3) maintain the frequency of the electric power system(s) within reasonable limits in accordance with Good Utility Practice and the criteria of the applicable regional reliability council or the North American Electric Reliability Corporation; and

(4) provide sufficient generating capacity to maintain operating reserves in accordance with Good Utility Practice.

Controllable Behind-the-Meter Generation means generation whose output can be controlled located at the same facility as a DARD or a Demand Response Asset, excluding: (1) generators whose output is separately metered and reported and (2) generators that cannot operate electrically synchronized to, and that are operated only when the facility loses its supply of power from, the New England Transmission System, or when undergoing related testing.

Coordinated External Transaction is an External Transaction at an external interface for which the enhanced scheduling procedures in Section III.1.10.7.A are implemented. A transaction to wheel energy into, out of or through the New England Control Area is not a Coordinated External Transaction.
Coordinated Transaction Scheduling means the enhanced scheduling procedures set forth in Section III.1.10.7.A.

Correction Limit means the date that is one hundred and one (101) calendar days from the last Operating Day of the month to which the data applied. As described in Section III.3.6.1 of Market Rule 1, this will be the period during which meter data corrections must be submitted unless they qualify for submission as a Requested Billing Adjustment under Section III.3.7 of Market Rule 1.

Cost of Energy Consumed (CEC) is one of four forms of compensation that may be paid to resources providing VAR Service under Schedule 2 of the OATT.

Cost of Energy Produced (CEP) is one of four forms of compensation that may be paid to resources providing VAR Service under Schedule 2 of the OATT.

Cost of New Entry (CONE) is the estimated cost of new entry ($/kW-month) for a capacity resource that is determined by the ISO for each Forward Capacity Auction pursuant to Section III.13.2.4.

Counterparty means the status in which the ISO acts as the contracting party, in its name and own right and not as an agent, to an agreement or transaction with a Customer (including assignments involving Customers) involving sale to the ISO, and/or purchase from the ISO, of Regional Transmission Service and market and other products and services, and other transactions and assignments involving Customers, all as described in the Tariff.

Covered Entity is defined in the ISO New England Billing Policy.

Credit Coverage is third-party credit protection obtained by the ISO, in the form of credit insurance coverage, a performance or surety bond, or a combination thereof.

Credit Qualifying means a Rated Market Participant that has an Investment Grade Rating and an Unrated Market Participant that satisfies the Credit Threshold.

Credit Threshold consists of the conditions for Unrated Market Participants outlined in Section II.B.2 of the ISO New England Financial Assurance Policy.

Critical Energy Infrastructure Information (CEII) is defined in Section 3.0(j) of the ISO New England Information Policy, which is Attachment D to the Tariff.

Current Ratio is, on any date, all of a Market Participant's or Non-Market Participant Transmission Customer's current assets divided by all of its current liabilities, in each case as shown on the most recent financial statements provided by such Market Participant or Non-Market Participant Transmission Customer to the ISO.

Curtailment is a reduction in the dispatch of a transaction that was scheduled, using transmission service, in response to a transfer capability shortage as a result of system reliability conditions.

Customer is a Market Participant, a Transmission Customer or another customer of the ISO.

Data Reconciliation Process means the process by which meter reconciliation and data corrections that are discovered by Governance Participants after the Invoice has been issued for a particular month or that are discovered prior to the issuance of the Invoice for the relevant month but not included in that Invoice or in the other Invoices for that month and are reconciled by the ISO on an hourly basis based on data submitted to the ISO by the Host Participant Assigned Meter Reader or Assigned Meter Reader.

Day-Ahead is the calendar day immediately preceding the Operating Day.

Day-Ahead Adjusted Load Obligation is defined in Section III.3.2.1(a)(1) of Market Rule 1.

Day-Ahead Ancillary Services means Day-Ahead Generation Contingency Reserve, Day-Ahead Replacement Energy Reserve, and Day-Ahead Energy Imbalance Reserve.

Day-Ahead Congestion Revenue is defined in Section III.3.2.1(i) of Market Rule 1.

Day-Ahead Demand Reduction Obligation is defined in Section III.3.2.1(a)(1) of Market Rule 1.

Day-Ahead Energy Imbalance Reserve is a form of reserve capability that is procured in the Day-Ahead Energy Market to help satisfy the Forecast Energy Requirement Demand Quantity described in Section III.1.8.6 of Market Rule 1.

Day-Ahead Energy Imbalance Reserve Demand Quantity is described in Section III.1.8.5(f) of Market Rule 1.

Day-Ahead Energy Imbalance Reserve Obligation is defined in Section III.3.2.1(a)(2) of Market Rule 1.

Day-Ahead Energy Market means: (i) prior to June 1, 2024, the schedule of commitments for the purchase or sale of energy, purchase of demand reductions, payment of Congestion Costs, and payment for losses developed by the ISO as a result of the offers and specifications submitted in accordance with Section III.1.10 of Market Rule 1, and (ii) commencing on June 1, 2024, the schedule of commitments for the purchase or sale of energy, the sale of ancillary services, purchase of demand reductions, payment of Congestion Costs, and payment for losses developed by the ISO as a result of the offers and specifications submitted in accordance with Sections III.1.8 and III.1.10 of Market Rule 1.

Day-Ahead Energy Market Congestion Charge/Credit is defined in Section III.3.2.1(f) of Market Rule 1.

Day-Ahead Energy Market Energy Charge/Credit is defined in Section III.3.2.1(f) of Market Rule 1.

Day-Ahead Energy Market Loss Charge/Credit is defined in Section III.3.2.1(f) of Market Rule 1.

Day-Ahead Energy Market NCPC Credit is an NCPC Credit calculated pursuant to Appendix F to Market Rule 1.

Day-Ahead External Transaction Export and Decrement Bid NCPC Credit is an NCPC Credit calculated pursuant to Appendix F to Market Rule 1.

Day-Ahead External Transaction Import and Increment Offer NCPC Credit is an NCPC Credit calculated pursuant to Appendix F to Market Rule 1.

Day-Ahead Four-Hour Reserve is a form of reserve capability that is procured in the Day-Ahead Energy Market based on the system-wide requirements described in Section III.1.8.5 of Market Rule 1.

Day-Ahead Four-Hour Reserve Obligation is defined in Section III.3.2.1(a)(2) of Market Rule 1.

Day-Ahead Generation Contingency Reserve means Day-Ahead Ten-Minute Spinning Reserve, Day-Ahead Ten-Minute Non-Spinning Reserve, and Day-Ahead Thirty-Minute Operating Reserve.

Day-Ahead Generation Obligation is defined in Section III.3.2.1(a)(1) of Market Rule 1.

Day-Ahead Load Obligation is defined in Section III.3.2.1(a)(1) of Market Rule 1.

Day-Ahead Locational Adjusted Net Interchange is defined in Section III.3.2.1(a)(1) of Market Rule 1.

Day-Ahead Loss Charges or Credits is defined in Section III.3.2.1(k) of Market Rule 1.

Day-Ahead Loss Revenue is defined in Section III.3.2.1(j) of Market Rule 1.

Day-Ahead Ninety-Minute Reserve is a form of reserve capability that is procured in the Day-Ahead Energy Market based on the system-wide requirements described in Section III.1.8.5 of Market Rule 1.

Day-Ahead Ninety-Minute Reserve Obligation is defined in Section III.3.2.1(a)(2) of Market Rule 1.

Day-Ahead Prices means the Locational Marginal Prices resulting from the Day-Ahead Energy Market, and commencing on June 1, 2024, the additional prices resulting from the Day-Ahead Energy Market described in Section III.2.6.2 of Market Rule 1.

Day-Ahead Replacement Energy Reserve means Day-Ahead Ninety-Minute Reserve and Day-Ahead Four-Hour Reserve.

Day-Ahead Ten-Minute Non-Spinning Reserve is a form of ten-minute reserve capability that is procured in the Day-Ahead Energy Market based on the system-wide requirements described in Section III.1.8.5 of Market Rule 1.

Day-Ahead Ten-Minute Non-Spinning Reserve Obligation is defined in Section III.3.2.1(a)(2) of Market Rule 1.

Day-Ahead Ten-Minute Spinning Reserve is a form of ten-minute reserve capability that is procured in the Day-Ahead Energy Market based on the system-wide requirements described in Section III.1.8.5 of Market Rule 1.

Day-Ahead Ten-Minute Spinning Reserve Demand Quantity is described in Section III.1.8.5(a) of Market Rule 1.

Day-Ahead Ten-Minute Spinning Reserve Obligation is defined in Section III.3.2.1(a)(2) of Market Rule 1.

Day-Ahead Thirty-Minute Operating Reserve is a form of reserve capability that is procured in the Day-Ahead Energy Market based on the system-wide requirements described in Section III.1.8.5 of Market Rule 1.

Day-Ahead Thirty-Minute Operating Reserve Obligation is defined in Section III.3.2.1(a)(2) of Market Rule 1.

Day-Ahead Total Four-Hour Reserve Demand Quantity is described in Section III.1.8.5(e) of Market Rule 1.

Day-Ahead Total Ninety-Minute Reserve Demand Quantity is described in Section III.1.8.5(d) of Market Rule 1.

Day-Ahead Total Ten-Minute Reserve Demand Quantity is described in Section III.1.8.5(b) of Market Rule 1.

Day-Ahead Total Thirty-Minute Operating Reserve Demand Quantity is described in Section III.1.8.5(c) of Market Rule 1.

DDP Dispatchable Resource is any Dispatchable Resource that the ISO dispatches using Desired Dispatch Points in the Resource's Dispatch Instructions.

Debt-to-Total Capitalization Ratio is, on any date, a Market Participant's or Non-Market Participant Transmission Customer's total debt (including all current borrowings) divided by its total shareholders' equity plus total debt, in each case as shown on the most recent financial statements provided by such Market Participant or Non-Market Participant Transmission Customer to the ISO.

Decrement Bid means a bid to purchase energy at a specified Location in the Day-Ahead Energy Market which is not associated with a physical load. An accepted Decrement Bid results in scheduled load at the specified Location in the Day-Ahead Energy Market.

Default Amount is all or any part of any amount due to be paid by any Covered Entity that the ISO, in its reasonable opinion, believes will not or has not been paid when due (other than in the case of a payment dispute for any amount due for transmission service under the OATT).

Default Period is defined in Section 3.3.h(i) of the ISO New England Billing Policy.

Delivering Party is the entity supplying capacity and/or energy to be transmitted at Point(s) of Receipt under the OATT.

Demand Bid means a request to purchase an amount of energy, at a specified Location, or an amount of energy at a specified price, that is associated with a physical load. A cleared Demand Bid in the Day-Ahead Energy Market results in scheduled load at the specified Location. Demand Bids submitted for use in the Real-Time Energy Market are specific to Dispatchable Asset Related Demands only.

Demand Bid Block-Hours are the Block-Hours assigned to the submitting Customer for each Demand Bid.

Demand Bid Cap is $2,000/MWh.

Demand Capacity Resource means an Existing Demand Capacity Resource or a New Demand Capacity Resource. There are three Demand Capacity Resource types: Active Demand Capacity Resources, On-Peak Demand Resources, and Seasonal Peak Demand Resources.

Demand Designated Entity is the entity designated by a Market Participant to receive Dispatch Instructions for Demand Response Resources in accordance with the provisions set forth in ISO New England Operating Procedure No. 14.

Demand Reduction Offer is an offer by a Market Participant with a Demand Response Resource to reduce demand.

Demand Reduction Offer Block-Hours are Block-Hours assigned to the Lead Market Participant for each Demand Reduction Offer. Blocks of the Demand Reduction Offer in effect for each hour will be totaled to determine the quantity of Demand Reduction Offer Block-Hours for a given day. In the case that a Resource has a Real-Time unit status of "unavailable" for the entire day, that day will not contribute to the quantity of Demand Reduction Offer Block-Hours. However, if the Resource has at least one hour of the day with a unit status of "available," the entire day will contribute to the quantity of Demand Reduction Offer Block-Hours.

Demand Reduction Threshold Price is a minimum offer price calculated pursuant to Section III.1.10.1A(f).

Demand Resource On-Peak Hours are hours ending 1400 through 1700, Monday through Friday on non-Demand Response Holidays during the months of June, July, and August and hours ending 1800 through 1900, Monday through Friday on non-Demand Response Holidays during the months of December and January.

Demand Resource Seasonal Peak Hours are those hours in which the actual, real-time hourly load, as measured using real-time telemetry (adjusted for transmission and distribution losses, and excluding load associated with Exports and Storage DARDs) for Monday through Friday on non-Demand Response Holidays, during the months of June, July, August, December, and January, as determined by the ISO, is

equal to or greater than 90% of the most recent 50/50 system peak load forecast, as determined by the ISO, for the applicable summer or winter season.

Demand Response Asset is an asset comprising the demand reduction capability of an individual end-use customer at a Retail Delivery Point or the aggregated demand reduction capability of multiple end-use customers from multiple delivery points (as described in Section III.8.1.1(f)) that has been registered in accordance with III.8.1.1.

Demand Response Available is the capability of the Demand Response Resource, in whole or in part, at any given time, to reduce demand in response to a Dispatch Instruction.

Demand Response Baseline is the expected baseline demand of an individual end-use metered customer or group of end-use metered customers as determined pursuant to Section III.8.2.

Demand Response Holiday is New Year's Day, Memorial Day, Independence Day, Labor Day, Veterans Day, Thanksgiving Day, and Christmas Day. If the holiday falls on a Saturday, the holiday will be observed on the preceding Friday; if the holiday falls on a Sunday, the holiday will be observed on the following Monday.

Demand Response Resource is an individual Demand Response Asset or aggregation of Demand Response Assets within a DRR Aggregation Zone that has been registered in accordance with Section III.8.1.2.

Demand Response Resource Notification Time is the period of time between the receipt of a startup Dispatch Instruction and the time the Demand Response Resource starts reducing demand.

Demand Response Resource Ramp Rate is the average rate, expressed in MW per minute, at which the Demand Response Resource can reduce demand.

Demand Response Resource Start-Up Time is the period of time between the time a Demand Response Resource starts reducing demand at the conclusion of the Demand Response Resource Notification Time and the time the resource can reach its Minimum Reduction and be ready for further dispatch by the ISO.

Designated Agent is any entity that performs actions or functions required under the OATT on behalf of the ISO, a Transmission Owner, a Schedule 20A Service Provider, an Eligible Customer, or a Transmission Customer.

Designated Blackstart Resource is a resource that meets the eligibility requirements specified in Schedule 16 of the OATT, which includes any resource referred to previously as a Category B Designated Blackstart Resource.

Designated Entity is the entity designated by a Market Participant to receive Dispatch Instructions for a Generator Asset and/or Dispatchable Asset Related Demand in accordance with the provisions set forth in ISO New England Operating Procedure No. 14.

Designated FCM Participant is any Lead Market Participant, including any Provisional Member that is a Lead Market Participant, transacting in any Forward Capacity Auction, reconfiguration auctions or Capacity Supply Obligation Bilateral for capacity that is otherwise required to provide additional financial assurance under the ISO New England Financial Assurance Policy.

Designated FTR Participant is a Market Participant, including FTR-Only Customers, transacting in the FTR Auction that is otherwise required to provide additional financial assurance under the ISO New England Financial Assurance Policy.

Desired Dispatch Point (DDP) means the control signal, expressed in megawatts, transmitted to direct the output, consumption, or demand reduction level of each Generator Asset, Dispatchable Asset Related Demand, or Demand Response Resource dispatched by the ISO in accordance with the asset's Offer Data.

Direct Assignment Facilities are facilities or portions of facilities that are constructed for the sole use/benefit of a particular Transmission Customer requesting service under the OATT or a Generator Owner requesting an interconnection. Direct Assignment Facilities shall be specified in a separate agreement among the ISO, Interconnection Customer and Transmission Customer, as applicable, and the Transmission Owner whose transmission system is to be modified to include and/or interconnect with the Direct Assignment Facilities, shall be subject to applicable Commission requirements, and shall be paid for by the Customer in accordance with the applicable agreement and the Tariff.

Directly Metered Assets are specifically measured by OP-18 compliant metering as currently described in Section IV (Metering and Recording for Settlements) of OP-18. Directly Metered Assets include all Tie-Line Assets, all Generator Assets, as well as some Load Assets. Load Assets for which the Host Participant is not the Assigned Meter Reader are considered Directly Metered Assets. In addition, the Host Participant Assigned Meter Reader determines which additional Load Assets are considered Directly Metered Assets and which ones are considered Profiled Load Assets based upon the Host Participant Assigned Meter Reader reporting systems and process by which the Host Participant Assigned Meter Reader allocates non-PTF losses.

Disbursement Agreement is the Rate Design and Funds Disbursement Agreement among the PTOs, as amended and restated from time to time.

Dispatch Instruction means directions given by the ISO to Market Participants, which may include instructions to start up, shut down, raise or lower generation, curtail or restore loads from Demand Response Resources, change External Transactions, or change the status or consumption of a Dispatchable Asset Related Demand in accordance with the Supply Offer, Demand Bid, or Demand Reduction Offer parameters. Such instructions may also require a change to the operation of a Pool Transmission Facility. Such instructions are given through either electronic or verbal means.

Dispatch Zone means a subset of Nodes located within a Load Zone established by the ISO for each Capacity Commitment Period pursuant to Section III.12.4A.

Dispatchable Asset Related Demand (DARD) is an Asset Related Demand that is capable of having its energy consumption modified in Real-Time in response to Dispatch Instructions. A DARD must be capable of receiving and responding to electronic Dispatch Instructions, must be able to increase or decrease energy consumption between its Minimum Consumption Limit and Maximum Consumption Limit in accordance with Dispatch Instructions, and must meet the technical requirements specified in the ISO New England Operating Procedures and Manuals.

Dispatchable Resource is any Generator Asset, Dispatchable Asset Related Demand, Demand Response Resource, or, with respect to the Regulation Market only, Alternative Technology Regulation Resource, that, during the course of normal operation, is capable of receiving and responding to electronic Dispatch Instructions in accordance with the parameters contained in the Resource's Supply Offer, Demand Bid, Demand Reduction Offer or Regulation Service Offer. A Resource that is normally classified as a

Dispatchable Resource remains a Dispatchable Resource when it is temporarily not capable of receiving and responding to electronic Dispatch Instructions.

Dispute Representatives are defined in 6.5.c of the ISO New England Billing Policy.

Disputed Amount is a Covered Entity's disputed amount due on any fully paid monthly Invoice and/or any amount believed to be due or owed on a Remittance Advice, as defined in Section 6 of the ISO New England Billing Policy.

Disputing Party, for the purposes of the ISO New England Billing Policy, is any Covered Entity seeking to recover a Disputed Amount.

Distributed Generation means generation directly connected to end-use customer load and located behind the end-use customer's Retail Delivery Point that reduces the amount of energy that would otherwise have been produced on the electricity network in the New England Control Area, provided that the facility's Net Supply Capability is (i) less than 5 MW or (ii) less than or equal to the Maximum Facility Load, whichever is greater.

DRR Aggregation Zone is a Dispatch Zone entirely within a single Reserve Zone or Rest of System or, where a Dispatch Zone is not entirely within a single Reserve Zone or Rest of System, each portion of the Dispatch Zone demarcated by the Reserve Zone boundary.

Do Not Exceed (DNE) Dispatchable Generator is any Generator Asset that is dispatched using Do Not Exceed Dispatch Points in its Dispatch Instructions and meets the criteria specified in Section III.1.11.3(e). Do Not Exceed Dispatchable Generators are Dispatchable Resources.

Do Not Exceed Dispatch Point is a Dispatch Instruction indicating a maximum output level that a DNE Dispatchable Generator must not exceed.

Dynamic De-List Bid is a bid that may be submitted by Existing Generating Capacity Resources, Existing Import Capacity Resources, and Existing Demand Capacity Resources in the Forward Capacity Auction below the Dynamic De-List Bid Threshold, as described in Section III.13.2.3.2(d) of Market Rule 1.

Dynamic De-List Bid Threshold is the price specified in Section III.13.1.2.3.1.A of Market Rule 1 associated with the submission of Dynamic De-List Bids in the Forward Capacity Auction.

EA Amount is defined in Section IV.B.2.2 of the Tariff.

Early Amortization Charge (EAC) is defined in Section IV.B.2 of the Tariff.

Early Amortization Working Capital Charge (EAWCC) is defined in Section IV.B.2 of the Tariff.

Early Payment Shortfall Funding Amount (EPSF Amount) is defined in Section IV.B.2.4 of the Tariff.

Early Payment Shortfall Funding Charge (EPSFC) is defined in Section IV.B.2 of the Tariff.

EAWW Amount is defined in Section IV.B.2.3 of the Tariff.

EBITDA-to-Interest Expense Ratio is, on any date, a Market Participant's or Non-Market Participant Transmission Customer's earnings before interest, taxes, depreciation and amortization in the most recent fiscal quarter divided by that Market Participant's or Non-Market Participant Transmission Customer's expense for interest in that fiscal quarter, in each case as shown on the most recent financial statements provided by such Market Participant or Non-Market Participant Transmission Customer to the ISO.

Economic Dispatch Point is the output, reduction, or consumption level to which a Resource would have been dispatched, based on the Resource's Supply Offer, Demand Reduction Offer, or Demand Bid and the Real-Time Price, and taking account of any operating limits, had the ISO not dispatched the Resource to another Desired Dispatch Point.

Economic Maximum Limit or Economic Max is the maximum available output, in MW, of a Generator Asset that a Market Participant offers to supply in the Day-Ahead Energy Market or Real-Time Energy Market, as reflected in the Generator Asset's Offer Data. This represents the highest MW output a Market Participant has offered for a Generator Asset for economic dispatch. A Market Participant must maintain an up-to-date Economic Maximum Limit (and where applicable, must provide the ISO with any telemetry required by ISO New England Operating Procedure No. 18 to allow the ISO to maintain an

updated Economic Maximum Limit) for all hours in which a Generator Asset has been offered into the Day-Ahead Energy Market or Real-Time Energy Market.

Economic Minimum Limit or Economic Min is (a) for a Generator Asset with an incremental heat rate, the maximum of: (i) the lowest sustainable output level as specified by physical design characteristics, environmental regulations or licensing limits; and (ii) the lowest sustainable output level at which a one MW increment increase in the output level would not decrease the incremental cost, calculated based on the incremental heat rate, of providing an additional MW of output, and (b) for a Generator Asset without an incremental heat rate, the lowest sustainable output level that is consistent with the physical design characteristics of the Generator Asset and with meeting all environmental regulations and licensing limits, and (c) for a Generator Asset undergoing Facility and Equipment Testing or auditing, the level to which the Generator Asset requests and is approved to operate or is directed to operate for purposes of completing the Facility and Equipment Testing or auditing, and (d) for Non-Dispatchable Resources the output level at which a Market Participant anticipates its Non-Dispatchable Resource will be available to operate based on fuel limitations, physical design characteristics, environmental regulations or licensing limits.

Economic Study is defined in Section 4.1(b) of Attachment K to the OATT.

Effective Offer is the Supply Offer, Demand Reduction Offer, or Demand Bid that is used for NCPC calculation purposes as specified in Section III.F.1(a).

EFT is electronic funds transfer.

Elective Transmission Upgrade is defined in Section I of Schedule 25 of the OATT.

Elective Transmission Upgrade Interconnection Customer is defined in Schedule 25 of the OATT.

Electric Reliability Organization (ERO) is defined in 18 C.F.R. § 39.1.

Electric Storage Facility is a storage facility that participates in the New England Markets as described in Section III.1.10.6 of Market Rule 1.

Eligible Customer is: (i) Any entity that is engaged, or proposes to engage, in the wholesale or retail electric power business is an Eligible Customer under the OATT. (ii) Any electric utility (including any power marketer), Federal power marketing agency, or any other entity generating electric energy for sale or for resale is an Eligible Customer under the OATT. Electric energy sold or produced by such entity may be electric energy produced in the United States, Canada or Mexico. However, with respect to transmission service that the Commission is prohibited from ordering by Section 212(h) of the Federal Power Act, such entity is eligible only if the service is provided pursuant to a state requirement that the Transmission Owner with which that entity is directly interconnected or the distribution company having the service territory in which that entity is located (if that entity is a retail customer) offer the unbundled transmission service or Local Delivery Service, or pursuant to a voluntary offer of such service by the Transmission Owner with which that entity is directly interconnected or the distribution company having the service territory in which that entity is located (if that entity is a retail customer). (iii) Any end user taking or eligible to take unbundled transmission service or Local Delivery Service pursuant to a state requirement that the Transmission Owner with which that end user is directly interconnected or the distribution company having the service territory in which that entity is located (if that entity is a retail customer) offer the transmission service or Local Delivery Service, or pursuant to a voluntary offer of such service by the Transmission Owner with which that end user is directly interconnected, or the distribution company having the service territory in which that entity is located (if that entity is a retail customer) is an Eligible Customer under the OATT.

Eligible FTR Bidder is an entity that has satisfied applicable financial assurance criteria, and shall not include the auctioneer, its Affiliates, and their officers, directors, employees, consultants and other representatives.

Emergency is an abnormal system condition on the bulk power systems of New England or neighboring Control Areas requiring manual or automatic action to maintain system frequency, or to prevent the involuntary loss of load, equipment damage, or tripping of system elements that could adversely affect the reliability of an electric system or the safety of persons or property; or a fuel shortage requiring departure from normal operating procedures in order to minimize the use of such scarce fuel; or a condition that requires implementation of Emergency procedures as defined in the ISO New England Manuals.

Emergency Condition means an Emergency has been declared by the ISO in accordance with the procedures set forth in the ISO New England Manuals and ISO New England Administrative Procedures.

Emergency Energy is energy transferred from one control area operator to another in an Emergency.

Emergency Minimum Limit or Emergency Min means the minimum output, in MWs, that a Generator Asset can deliver for a limited period of time without exceeding specified limits of equipment stability and operating permits.

EMS is energy management system.

End-of-Round Price is the lowest price associated with a round of a Forward Capacity Auction, as described in Section III.13.2.3.1 of Market Rule 1.

End User Participant is defined in Section 1 of the Participants Agreement.

Energy is power produced in the form of electricity, measured in kilowatthours or megawatthours.

Energy Administration Service (EAS) is the service provided by the ISO, as described in Schedule 2 of Section IV.A of the Tariff.

Energy Call Option Offer is a form of offer that may be submitted by Market Participants in the Day-Ahead Energy Market in accordance with Section III.1.8 of Market Rule 1, and that is used by the ISO to determine obligations for Day-Ahead Ancillary Services as defined in Section III.3.2.1(a)(2) of Market Rule 1.

Energy Call Option Strike Price is specified in Section III.1.8. 3 of Market Rule 1.

Energy Component means the Locational Marginal Price at the reference point.

Energy Efficiency is installed measures (e.g., products, equipment, systems, services, practices and/or strategies) on end-use customer facilities that reduce the total amount of electrical energy needed, while delivering a comparable or improved level of end-use service. Such measures include, but are not limited to, the installation of more energy efficient lighting, motors, refrigeration, HVAC equipment and control systems, envelope measures, operations and maintenance procedures, and industrial process equipment.

Energy Imbalance Service is the form of Ancillary Service described in Schedule 4 of the OATT.

Energy Market is, collectively, the Day-Ahead Energy Market and the Real-Time Energy Market.

Energy Non-Zero Spot Market Settlement Hours are the sum of the hours for which the Customer has a positive or negative Real-Time System Adjusted Net Interchange or for which the Customer has a positive or negative Real-Time Demand Reduction Obligation as determined by the ISO settlement process for the Energy Market.

Energy Offer Floor is negative $150/MWh.

Energy Transaction Units (Energy TUs) are the sum for the month for a Customer of Bilateral Contract Block-Hours, Demand Bid Block-Hours, Asset Related Demand Bid Block-Hours, Supply Offer Block-Hours, Demand Reduction Offer Block-Hours, and Energy Non-Zero Spot Market Settlement Hours.

Equipment Damage Reimbursement is the compensation paid to the owner of a Designated Blackstart Resource as specified in Section 5.5 of Schedule 16 to the OATT.

Equivalent Demand Forced Outage Rate (EFORd) means the portion of time a unit is in demand, but is unavailable due to forced outages.

Estimated Capacity Load Obligation is, for the purposes of the ISO New England Financial Assurance Policy, a Market Participant's share of Zonal Capacity Obligation from the latest available month, adjusted as appropriate to account for any relevant Capacity Load Obligation Bilaterals, HQICCs, and Self-Supplied FCA Resource designations for the applicable month.

Establish Claimed Capability Audit is the audit performed pursuant to Section III.1.5.1.2.

Excepted Transaction is a transaction specified in Section II.40 of the Tariff for the applicable period specified in that Section.

Existing Capacity Qualification Deadline is a deadline, specified in Section III.13.1.10 of Market Rule 1, for submission of certain qualification materials for the Forward Capacity Auction, as discussed in Section III.13.1 of Market Rule 1.

Existing Capacity Qualification Package is information submitted for certain existing resources prior to participation in the Forward Capacity Auction, as described in Section III.13.1 of Market Rule 1.

Existing Capacity Resource is any resource that does not meet any of the eligibility criteria to participate in the Forward Capacity Auction as a New Capacity Resource.

Existing Capacity Retirement Deadline is a deadline, specified in Section III.13.1.10 of Market Rule 1, for submission of certain qualification materials for the Forward Capacity Auction, as discussed in Section III.13.1 of Market Rule 1.

Existing Capacity Retirement Package is information submitted for certain existing resources prior to participation in the Forward Capacity Auction, as described in Section III.13.1 of Market Rule 1.

Existing Demand Capacity Resource is a type of Demand Capacity Resource participating in the Forward Capacity Market, as defined in Section III.13.1.4.2 of Market Rule 1.

Existing Generating Capacity Resource is a type of resource participating in the Forward Capacity Market, as defined in Section III.13.1.2.1 of Market Rule 1.

Existing Import Capacity Resource is a type of resource participating in the Forward Capacity Market, as defined in Section III.13.1.3.1 of Market Rule 1.

Expedited Study Request is defined in Section II.34.7 of the OATT.

Export-Adjusted LSR is as defined in Section III.12.4(b)(ii).

Export Bid is a bid that may be submitted by certain resources in the Forward Capacity Auction to export capacity to an external Control Area, as described in Section III.13.1.2.3.1.3 of Market Rule 1.

Exports are Real-Time External Transactions, which are limited to sales from the New England Control Area, for exporting energy out of the New England Control Area.

External Elective Transmission Upgrade (External ETU) is defined in Section I of Schedule 25 of the OATT.

External Market Monitor means the person or entity appointed by the ISO Board of Directors pursuant to Section III.A.1.2 of Appendix A of Market Rule 1 to carry out the market monitoring and mitigation functions specified in Appendix A and elsewhere in Market Rule 1.

External Node is a proxy bus or buses used for establishing a Locational Marginal Price for energy received by Market Participants from, or delivered by Market Participants to, a neighboring Control Area or for establishing Locational Marginal Prices associated with energy delivered through the New England Control Area by Non-Market Participants for use in calculating Non-Market Participant Congestion Costs and loss costs.

External Resource means a generation resource located outside the metered boundaries of the New England Control Area.

External Transaction is the import of external energy into the New England Control Area by a Market Participant or the export of internal energy out of the New England Control Area by a Market Participant in the Day-Ahead Energy Market and/or Real-Time Energy Market, or the wheeling of external energy through the New England Control Area by a Market Participant or a Non-Market Participant in the Real-Time Energy Market.

External Transaction Cap is $2,000/MWh for External Transactions other than Coordinated External Transactions and $1,000/MWh for Coordinated External Transactions.

External Transaction Floor is the Energy Offer Floor for External Transactions other than Coordinated External Transactions and negative $1,000/MWh for Coordinated External Transactions.

External Transmission Project is a transmission project comprising facilities located wholly outside the New England Control Area and regarding which an agreement has been reached whereby New England ratepayers will support all or a portion of the cost of the facilities.

Facilities Study is an engineering study conducted pursuant to the OATT by the ISO (or, in the case of Local Service or interconnections to Local Area Facilities as defined in the TOA, by one or more affected PTOs) or some other entity designated by the ISO in consultation with any affected Transmission Owner(s), to determine the required modifications to the PTF and Non-PTF, including the cost and

scheduled completion date for such modifications, that will be required to provide a requested transmission service or interconnection on the PTF and Non-PTF.

Facility and Equipment Testing means operation of a Resource to evaluate the functionality of the facility or equipment utilized in the operation of the facility.

Failure to Maintain Blackstart Capability is a failure of a Blackstart Owner or Designated Blackstart Resource to meet the Blackstart Service Minimum Criteria or Blackstart Service obligations, but does not include a Failure to Perform During a System Restoration event.

Failure to Perform During a System Restoration is a failure of a Blackstart Owner or Designated Blackstart Resource to follow ISO or Local Control Center dispatch instructions or perform in accordance with the dispatch instructions or the Blackstart Service Minimum Criteria and Blackstart Service obligations, described within the ISO New England Operating Documents, during a restoration of the New England Transmission System.

Fast Start Demand Response Resource is a Demand Response Resource that meets the following criteria: (i) Minimum Reduction Time does not exceed one hour; (ii) Minimum Time Between Reductions does not exceed one hour; (iii) Demand Response Resource Start-Up Time plus Demand Response Resource Notification Time does not exceed 30 minutes; (iv) has personnel available to respond to Dispatch Instructions or has automatic remote response capability; and (v) is capable of receiving and acknowledging a Dispatch Instruction electronically.

Fast Start Generator means a Generator Asset that the ISO can dispatch to an on-line or off-line state through electronic dispatch and that meets the following criteria: (i) Minimum Run Time does not exceed one hour; (ii) Minimum Down Time does not exceed one hour; (iii) cold Notification Time plus cold Start-Up Time does not exceed 30 minutes; (iv) available for dispatch (when it is either in an on-line or off-line state) and manned or has automatic remote dispatch capability; and (v) capable of receiving and acknowledging a start-up or shut-down Dispatch Instruction electronically.

FCA Cleared Export Transaction is defined in Section III.1.10.7(f)(ii) of Market Rule 1.

FCA Qualified Capacity is the Qualified Capacity that is used in a Forward Capacity Auction.

FCM Capacity Charge Requirements are calculated in accordance with Section VII.C of the ISO New England Financial Assurance Policy.

FCM Charge Rate is calculated in accordance with Section VII.C of the ISO New England Financial Assurance Policy.

FCM Commercial Operation is defined in Section III.13.3.8 of Market Rule 1.

FCM Deposit is calculated in accordance with Section VII.B.1 of the ISO New England Financial Assurance Policy.

FCM Financial Assurance Requirements are described in Section VII of the ISO New England Financial Assurance Policy.

Final Forward Reserve Obligation is calculated in accordance with Section III.9.8(a) of Market Rule 1.

Financial Assurance Default results from a Market Participant or Non-Market Participant Transmission Customer's failure to comply with the ISO New England Financial Assurance Policy.

Financial Assurance Obligations relative to the ISO New England Financial Assurance Policy are determined in accordance with Section III.A(v) of the ISO New England Financial Assurance Policy.

Financial Transmission Right (FTR) is a financial instrument that evidences the rights and obligations specified in Sections III.5.2.2 and III.7 of the Tariff.

Firm Point-To-Point Service is service which is arranged for and administered between specified Points of Receipt and Delivery in accordance with Part II.C of the OATT.

Firm Transmission Service is Regional Network Service, Through or Out Service, service for Excepted Transactions, firm MTF Service, firm OTF Service, and firm Local Service.

Flexible DNE Dispatchable Generator is any DNE Dispatchable Generator that meets the following criteria: (i) Minimum Run Time does not exceed one hour; (ii) Minimum Down Time does not exceed one hour; and (iii) cold Notification Time plus cold Start-Up Time does not exceed 30 minutes.

Force Majeure - An event of Force Majeure means any act of God, labor disturbance, act of the public enemy or terrorists, war, invasion, insurrection, riot, fire, storm or flood, ice, explosion, breakage or accident to machinery or equipment, any curtailment, order, regulation or restriction imposed by governmental military or lawfully established civilian authorities, or any other cause beyond the control of the ISO, a Transmission Owner, a Schedule 20A Service Provider, or a Customer, including without limitation, in the case of the ISO, any action or inaction by a Customer, a Schedule 20A Service Provider, or a Transmission Owner, in the case of a Transmission Owner, any action or inaction by the ISO, any Customer, a Schedule 20A Service Provider, or any other Transmission Owner, in the case of a Schedule 20A Service Provider, any action or inaction by the ISO, any Customer, a Transmission Owner, or any other Schedule 20A Service Provider, and, in the case of a Transmission Customer, any action or inaction by the ISO, a Schedule 20A Service Provider, or any Transmission Owner.

Forecast Energy Requirement Demand Quantity is described in Section III.1.8.6 of Market Rule 1.

Forecast Energy Requirement Price is determined in accordance with Section III.2.6.2(a) of Market Rule 1.

Formal Warning is defined in Section III.B.4.1.1 of Appendix B of Market Rule 1.

Formula-Based Sanctions are defined in Section III.B.4.1.3 of Appendix B of Market Rule 1.

Forward Capacity Auction (FCA) is the annual Forward Capacity Market auction process described in Section III.13.2 of Market Rule 1.

Forward Capacity Auction Starting Price is calculated in accordance with Section III.13.2.4 of Market Rule 1.

Forward Capacity Market (FCM) is the forward market for procuring capacity in the New England Control Area, as described in Section III.13 of Market Rule 1.

Forward Energy Inventory Election is the total MWh value for which a Market Participant elects to be compensated at the forward rate in the inventoried energy program as described in Section III.K.1(d) of Market Rule 1.

Forward LNG Inventory Election is the portion of a Market Participant's Forward Energy Inventory Election attributed to liquefied natural gas in the inventoried energy program as described in Section III.K.1(d) of Market Rule 1.

Forward Reserve means TMNSR and TMOR purchased by the ISO on a forward basis on behalf of Market Participants as provided for in Section III.9 of Market Rule 1.

Forward Reserve Assigned Megawatts is the amount of Forward Reserve, in megawatts, that a Market Participant assigns to eligible Forward Reserve Resources to meet its Forward Reserve Obligation as defined in Section III.9.4.1 of Market Rule 1.

Forward Reserve Auction is the periodic auction conducted by the ISO in accordance with Section III.9 of Market Rule 1 to procure Forward Reserve.

Forward Reserve Auction Offers are offers to provide Forward Reserve to meet system and Reserve Zone requirements as submitted by a Market Participant in accordance with Section III.9.3 of Market Rule 1.

Forward Reserve Charge is a Market Participant's share of applicable system and Reserve Zone Forward Reserve costs attributable to meeting the Forward Reserve requirement as calculated in accordance with Section III.9.9 of Market Rule 1.

Forward Reserve Clearing Price is the clearing price for TMNSR or TMOR, as applicable, for the system and each Reserve Zone resulting from the Forward Reserve Auction as defined in Section III.9.4 of Market Rule 1.

Forward Reserve Credit is the credit received by a Market Participant that is associated with that Market Participant's Final Forward Reserve Obligation as calculated in accordance with Section III.9.8 of Market Rule 1.

Forward Reserve Delivered Megawatts are calculated in accordance with Section III.9.6.5 of Market Rule 1.

Forward Reserve Delivery Period is defined in Section III.9.1 of Market Rule 1.

Forward Reserve Failure-to-Activate Megawatts are calculated in accordance with Section III.9.7.2(a) of Market Rule 1.

Forward Reserve Failure-to-Activate Penalty is the penalty associated with a Market Participant's failure to activate Forward Reserve when requested to do so by the ISO and is defined in Section III.9.7.2 of Market Rule 1.

Forward Reserve Failure-to-Activate Penalty Rate is specified in Section III.9.7.2 of Market Rule 1.

Forward Reserve Failure-to-Reserve, as specified in Section III.9.7.1 of Market Rule 1, occurs when a Market Participant's Forward Reserve Delivered Megawatts for a Reserve Zone in an hour is less than that Market Participant's Forward Reserve Obligation for that Reserve Zone in that hour. Under these circumstances the Market Participant pays a penalty based upon the Forward Reserve Failure-to-Reserve Penalty Rate and that Market Participant's Forward Reserve Failure-to-Reserve Megawatts.

Forward Reserve Failure-to-Reserve Megawatts are calculated in accordance with Section III.9.7.1(a) of Market Rule 1.

Forward Reserve Failure-to-Reserve Penalty is the penalty associated with a Market Participant's failure to reserve Forward Reserve and is defined in Section III.9.7.1 of Market Rule 1.

Forward Reserve Failure-to-Reserve Penalty Rate is specified in Section III.9.7.1(b)(ii) of Market Rule 1.

Forward Reserve Fuel Index is the index or set of indices used to calculate the Forward Reserve Threshold Price as defined in Section III.9.6.2 of Market Rule 1.

Forward Reserve Heat Rate is the heat rate as defined in Section III.9.6.2 of Market Rule 1 that is used to calculate the Forward Reserve Threshold Price.

Forward Reserve Market is a market for forward procurement of two reserve products, Ten-Minute Non-Spinning Reserve (TMNSR) and Thirty-Minute Operating Reserve (TMOR).

Forward Reserve MWs are those megawatts assigned to specific eligible Forward Reserve Resources which convert a Forward Reserve Obligation into a Resource-specific obligation.

Forward Reserve Obligation is a Market Participant's amount, in megawatts, of Forward Reserve that cleared in the Forward Reserve Auction and adjusted, as applicable, to account for bilateral transactions that transfer Forward Reserve Obligations.

Forward Reserve Obligation Charge is defined in Section III.10.4 of Market Rule 1.

Forward Reserve Offer Cap is $9,000/megawatt-month.

Forward Reserve Payment Rate is defined in Section III.9.8 of Market Rule 1.

Forward Reserve Procurement Period is defined in Section III.9.1 of Market Rule 1.

Forward Reserve Qualifying Megawatts refer to all or a portion of a Forward Reserve Resource's capability offered into the Real-Time Energy Market at energy offer prices above the applicable Forward Reserve Threshold Price that are calculated in accordance with Section III.9.6.4 of Market Rule 1.

Forward Reserve Resource is a Resource that meets the eligibility requirements defined in Section III.9.5.2 of Market Rule 1 that has been assigned Forward Reserve Obligation by a Market Participant.

Forward Reserve Threshold Price is the minimum price at which assigned Forward Reserve Megawatts are required to be offered into the Real-Time Energy Market as calculated in Section III.9.6.2 of Market Rule 1.

FTR Auction is the periodic auction of FTRs conducted by the ISO in accordance with Section III.7 of Market Rule 1.

FTR Auction Revenue is the revenue collected from the sale of FTRs in FTR Auctions. FTR Auction Revenue is payable to FTR Holders who submit their FTRs for sale in the FTR Auction in accordance with Section III.7 of Market Rule 1 and to ARR Holders and Incremental ARR Holders in accordance with Appendix C of Market Rule 1.

FTR Credit Test Percentage is calculated in accordance with Section III.B.1(b) of the ISO New England Financial Assurance Policy.

FTR Financial Assurance Requirements are described in Section VI of the ISO New England Financial Assurance Policy.

FTR Holder is an entity that acquires an FTR through the FTR Auction to Section III.7 of Market Rule 1 and registers with the ISO as the holder of the FTR in accordance with Section III.7 of Market Rule 1 and applicable ISO New England Manuals.

FTR-Only Customer is a Market Participant that transacts in the FTR Auction and that does not participate in other markets or programs of the New England Markets. References in this Tariff to a "Non-Market Participant FTR Customers" and similar phrases shall be deemed references to an FTR-Only Customer.

FTR Settlement Risk Financial Assurance is an amount of financial assurance required by a Designated FTR Participant for each bid submission into an FTR Auction and for each bid awarded to the individual participant in an FTR Auction. This amount is calculated pursuant to Section VI.A of the ISO New England Financial Assurance Policy.

GADS Data means data submitted to the NERC for collection into the NERC's Generating Availability Data System (GADS).

Gap Request for Proposals (Gap RFP) is defined in Section III.11 of Market Rule 1.

Gas Day means a period of 24 consecutive hours beginning at 0900 hrs Central Time.

Generating Capacity Resource means a New Generating Capacity Resource or an Existing Generating Capacity Resource.

Generator Asset is a device (or a collection of devices) that is capable of injecting real power onto the grid that has been registered as a Generator Asset in accordance with the Asset Registration Process.

Generator Imbalance Service is the form of Ancillary Service described in Schedule 10 of the OATT.

Generator Interconnection Related Upgrade is an addition to or modification of the New England Transmission System (pursuant to Section II.47.1, Schedule 22 or Schedule 23 of the OATT) to effect the interconnection of a new generating unit or an existing generating unit whose energy capability or capacity capability is being materially changed and increased whether or not the interconnection is being effected to meet the Capacity Capability Interconnection Standard or the Network Capability Interconnection Standard. As to Category A Projects (as defined in Schedule 11 of the OATT), a Generator Interconnection Related Upgrade also includes an upgrade beyond that required to satisfy the Network Capability Interconnection Standard (or its predecessor) for which the Generator Owner has committed to pay prior to October 29, 1998.

Generator Owner is the owner, in whole or part, of a generating unit whether located within or outside the New England Control Area.

Good Utility Practice means any of the practices, methods and acts engaged in or approved by a significant portion of the electric utility industry during the relevant time period, or any of the practices, methods and acts which, in the exercise of reasonable judgment in light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety and expedition. Good Utility Practice is not intended to be limited to the optimum practice, method, or act to the exclusion of all others, but rather includes all acceptable practices, methods, or acts generally accepted in the region, including those practices required by Federal Power Act Section 215(a)(4).

Governance Only Member is defined in Section 1 of the Participants Agreement.

Governance Participant is defined in the Participants Agreement.

Governing Documents, for the purposes of the ISO New England Billing Policy, are the Transmission, Markets and Services Tariff and ISO Participants Agreement.

Governing Rating is the lowest corporate rating from any Rating Agency for that Market Participant, or, if the Market Participant has no corporate rating, then the lowest rating from any Rating Agency for that Market Participant’s senior unsecured debt.

Grandfathered Agreements (GAs) is a transaction specified in Section II.45 for the applicable period specified in that Section.

Grandfathered Intertie Agreement (GIA) is defined pursuant to the TOA.

Handy-Whitman Index of Public Utility Construction Costs is the Total Other Production Plant index shown in the Cost Trends of Electric Utility Construction for the North Atlantic Region as published in the Handy-Whitman Index of Public Utility Construction Costs.

Highgate Transmission Facilities (HTF) are existing U. S.-based transmission facilities covered under the Agreement for Joint Ownership, Construction and Operation of the Highgate Transmission Interconnection dated as of August 1, 1984 including (1) the whole of a 200 megawatt high-voltage, back-to-back, direct-current converter facility located in Highgate, Vermont and (2) a 345 kilovolt transmission line within Highgate and Franklin, Vermont (which connects the converter facility at the U.S.-Canadian border to a Hydro-Quebec 120 kilovolt line in Bedford, Quebec). The HTF include any upgrades associated with increasing the capacity or changing the physical characteristics of these facilities as defined in the above stated agreement dated August 1, 1984 until the Operations Date, as defined in the TOA. The current HTF rating is a nominal 225 MW. The HTF are not defined as PTF. Coincident with the Operations Date and except as stipulated in Schedules, 9, 12, and Attachment F to the OATT, HTF shall be treated in the same manner as PTF for purposes of the OATT and all references to PTF in the OATT shall be deemed to apply to HTF as well. The treatment of the HTF is not intended to establish any binding precedent or presumption with regard to the treatment for other transmission facilities within the New England Transmission System (including HVDC, MTF, or Control Area Interties) for purposes of the OATT.

Host Participant or Host Utility is a Market Participant or a Governance Participant transmission or distribution provider that reconciles the loads within the metering domain with OP-18 compliant metering.

Hourly Charges are defined in Section 1.3 of the ISO New England Billing Policy.

Hourly PER is calculated in accordance with Section III.13.7.1.2.1 of Market Rule 1.

Hourly Requirements are determined in accordance with Section III.A(i) of the ISO New England Financial Assurance Policy.

Hourly Shortfall NCPC Credit is an NCPC Credit calculated pursuant to Appendix F to Market Rule 1.

Hub is a specific set of pre-defined Nodes for which a Locational Marginal Price will be calculated for the Day-Ahead Energy Market and Real-Time Energy Market and which can be used to establish a reference price for energy purchases and the transfer of Day-Ahead Adjusted Load Obligations and Real-Time Adjusted Load Obligations and for the designation of FTRs.

Hub Price is calculated in accordance with Section III.2.8 of Market Rule 1.

HQ Interconnection Capability Credit (HQICC) is a monthly value reflective of the annual installed capacity benefits of the Phase I/II HVDC-TF, as determined by the ISO, using a standard methodology on file with the Commission, in conjunction with the setting of the Installed Capacity Requirement. An appropriate share of the HQICC shall be assigned to an IRH if the Phase I/II HVDC-TF support costs are paid by that IRH and such costs are not included in the calculation of the Regional Network Service rate. The share of HQICC allocated to such an eligible IRH for a month is the sum in kilowatts of (1)(a) the IRH's percentage share, if any, of the Phase I Transfer Capability times (b) the Phase I Transfer Credit, plus (2)(a) the IRH's percentage share, if any, of the Phase II Transfer Capability, times (b) the Phase II Transfer Credit. The ISO shall establish appropriate HQICCs to apply for an IRH which has such a percentage share.

Import Capacity Resource means an Existing Import Capacity Resource or a New Import Capacity Resource offered to provide capacity in the New England Control Area from an external Control Area.

Inadvertent Energy Revenue is defined in Section III.3.2.1(o) of Market Rule 1.

Inadvertent Energy Revenue Charges or Credits is defined in Section III.3.2.1(p) of Market Rule 1.

Inadvertent Interchange means the difference between net actual energy flow and net scheduled energy flow into or out of the New England Control Area.

Increment Offer means an offer to sell energy at a specified Location in the Day-Ahead Energy Market which is not associated with a physical supply. An accepted Increment Offer results in scheduled supply at the specified Location in the Day-Ahead Energy Market.

Incremental ARR is an ARR provided in recognition of a participant-funded transmission system upgrade pursuant to Appendix C of this Market Rule.

Incremental ARR Holder is an entity which is the record holder of an Incremental Auction Revenue Right in the register maintained by the ISO.

Incremental Cost of Reliability Service is described in Section III.13.2.5.2.5.2 of Market Rule 1.

Independent Transmission Company (ITC) is a transmission entity that assumes certain responsibilities in accordance with Section 10.05 of the Transmission Operating Agreement and Attachment M to the OATT, subject to the acceptance or approval of the Commission and a finding of the Commission that the transmission entity satisfies applicable independence requirements.

Information Request is a request from a potential Disputing Party submitted in writing to the ISO for access to Confidential Information.

Initial Market Participant Financial Assurance Requirement is calculated for new Market Participants and Returning Market Participants, other than an FTR-Only Customer or a Governance Only Member, according to Section IV of the ISO New England Financial Assurance Policy.

Installed Capacity Requirement means the level of capacity required to meet the reliability requirements defined for the New England Control Area, as described in Section III.12 of Market Rule 1.

Interchange Transactions are transactions deemed to be effected under Market Rule 1.

Interconnecting Transmission Owner has the meaning specified in Section I of Schedule 22, Attachment 1 to Schedule 23, and Section I of Schedule 25 of the OATT.

Interconnection Agreement is the “Large Generator Interconnection Agreement”, the “Small Generator Interconnection Agreement”, or the “Elective Transmission Upgrade Interconnection Agreement”

pursuant to Schedules 22, 23 or 25 of the ISO OATT or an interconnection agreement approved by the Commission prior to the adoption of the Interconnection Procedures.

Interconnection Customer has the meaning specified in Section I of Schedule 22, Attachment 1 to Schedule 23, and Section I of Schedule 25 of the OATT.

Interconnection Feasibility Study Agreement has the meaning specified in Section I of Schedule 22, Attachment 1 to Schedule 23, or Section I of Schedule 25 of the OATT.

Interconnection Procedure is the “Large Generator Interconnection Procedures”, the “Small Generator Interconnection Procedures”, or the “Elective Transmission Upgrade Interconnection Procedures” pursuant to Schedules 22, 23, and 25 of the ISO OATT.

Interconnection Reliability Operating Limit (IROL) has the meaning specified in the Glossary of Terms Used in NERC Reliability Standards.

Interconnection Request has the meaning specified in Section I of Schedule 22, Attachment 1 to Schedule 23, or Section I of Schedule 25 of the OATT.

Interconnection Rights Holder(s) (IRH) has the meaning given to it in Schedule 20A to Section II of this Tariff.

Interconnection System Impact Study Agreement has the meaning specified in Section I of Schedule 22, Attachment 1 to Schedule 23 and Section I of Schedule 25 of the OATT.

Interest is interest calculated in the manner specified in Section II.8.3.

Interface Bid is a unified real-time bid to simultaneously purchase and sell energy on each side of an external interface for which the enhanced scheduling procedures in Section III.1.10.7.A are implemented.

Intermittent Power Resource is a wind, solar, run of river hydro or other renewable resource that does not have control over its net power output.

Internal Bilateral for Load is an internal bilateral transaction under which the buyer receives a reduction in Real-Time Load Obligation and the seller receives a corresponding increase in Real-Time Load Obligation in the amount of the sale, in MWs. An Internal Bilateral for Load transaction is only applicable in the Real-Time Energy Market.

Internal Bilateral for Market for Energy is an internal bilateral transaction for Energy which applies in the Day-Ahead Energy Market and Real-Time Energy Market or just the Real-Time Energy Market under which the buyer receives a reduction in Day-Ahead Adjusted Load Obligation and Real-Time Adjusted Load Obligation and the seller receives a corresponding increase in Day-Ahead Adjusted Load Obligation and Real-Time Adjusted Load Obligation in the amount of the sale, in MWs.

Internal Elective Transmission Upgrade (Internal ETU) is defined in Section I of Schedule 25 of the OATT.

Internal Market Monitor means the department of the ISO responsible for carrying out the market monitoring and mitigation functions specified in Appendix A and elsewhere in Market Rule 1.

Interregional Planning Stakeholder Advisory Committee (IPSAC) is the committee described as such in the Northeast Planning Protocol.

Interregional Transmission Project is a transmission project located within the New England Control Area and one or more of the neighboring transmission planning regions.

Interruption Cost is the amount, in dollars, that must be paid to a Market Participant each time the Market Participant’s Demand Response Resource is scheduled or dispatched in the New England Markets to reduce demand.

Inventoried Energy Day is an Operating Day that occurs in the months of December, January, or February during the winter of 2023-2024 (inventoried energy program) and for which the average of the high temperature and the low temperature on that Operating Day, as measured and reported by the National Weather Service at Bradley International Airport in Windsor Locks, Connecticut, is less than or equal to 17 degrees Fahrenheit, as described in Section III.K.3.1 of Market Rule 1.

Investment Grade Rating, for a Market (other than an FTR-Only Customer) or Non-Market Participant Transmission Customer, is either (a) a corporate investment grade rating from one or more of the Rating Agencies, or (b) if the Market Participant or Non-Market Participant Transmission Customer does not have a corporate rating from one of the Rating Agencies, then an investment grade rating for the Market Participant's or Non-Market Participant Transmission Customer's senior unsecured debt from one or more of the Rating Agencies.

Invoice is a statement issued by the ISO for the net Charge owed by a Covered Entity pursuant to the ISO New England Billing Policy.

Invoice Date is the day on which the ISO issues an Invoice.

ISO means ISO New England Inc.

ISO Charges, for the purposes of the ISO New England Billing Policy, are both Non-Hourly Charges and Hourly Charges.

ISO Control Center is the primary control center established by the ISO for the exercise of its Operating Authority and the performance of functions as an RTO.

ISO-Initiated Claimed Capability Audit is the audit performed pursuant to Section III.1.5.1.4.

ISO New England Administrative Procedures means procedures adopted by the ISO to fulfill its responsibilities to apply and implement ISO New England System Rules.

ISO New England Billing Policy is Exhibit ID to Section I of the Transmission, Markets and Services Tariff.

ISO New England Filed Documents means the Transmission, Markets and Services Tariff, including but not limited to Market Rule 1, the Participants Agreement, the Transmission Operating Agreement or other documents that affect the rates, terms and conditions of service.

ISO New England Financial Assurance Policy is Exhibit IA to Section I of the Transmission, Markets and Services Tariff.

ISO New England Information Policy is the policy establishing guidelines regarding the information received, created and distributed by Market Participants and the ISO in connection with the settlement, operation and planning of the System, as the same may be amended from time to time in accordance with the provisions of this Tariff. The ISO New England Information Policy is Attachment D to the Transmission, Markets and Services Tariff.

ISO New England Manuals are the manuals implementing Market Rule 1, as amended from time to time in accordance with the Participants Agreement. Any elements of the ISO New England Manuals that substantially affect rates, terms, and/or conditions of service shall be filed with the Commission under Section 205 of the Federal Power Act.

ISO New England Operating Documents are the Tariff and the ISO New England Operating Procedures.

ISO New England Operating Procedures (OPs) are the ISO New England Planning Procedures and the operating guides, manuals, procedures and protocols developed and utilized by the ISO for operating the ISO bulk power system and the New England Markets.

ISO New England Planning Procedures are the procedures developed and utilized by the ISO for planning the ISO bulk power system.

ISO New England System Rules are Market Rule 1, the ISO New England Information Policy, the ISO New England Administrative Procedures, the ISO New England Manuals and any other system rules, procedures or criteria for the operation of the New England Transmission System and administration of the New England Markets and the Transmission, Markets and Services Tariff.

ITC Agreement is defined in Attachment M to the OATT.

ITC Rate Schedule is defined in Section 3.1 of Attachment M to the OATT.

ITC System is defined in Section 2.2 of Attachment M to the OATT.

ITC System Planning Procedures is defined in Section 15.4 of Attachment M to the OATT.

Joint ISO/RTO Planning Committee (JIPC) is the committee described as such in the Northeastern Planning Protocol.

Late Payment Account is a segregated interest-bearing account into which the ISO deposits Late Payment Charges due from ISO Charges and interest owed from participants for late payments that are collected and not distributed to the Covered Entities, until the Late Payment Account Limit is reached, under the ISO New England Billing Policy and penalties collected under the ISO New England Financial Assurance Policy.

Late Payment Account Limit is defined in Section 4.2 of the ISO New England Billing Policy.

Late Payment Charge is defined in Section 4.1 of the ISO New England Billing Policy.

Lead Market Participant, for purposes other than the Forward Capacity Market, is the entity authorized to submit Supply Offers, Demand Bids or Demand Reduction Offers for a Resource and to whom certain Energy TUs are assessed under Schedule 2 of Section IV.A of the Tariff. For purposes of the Forward Capacity Market, the Lead Market Participant is the entity designated to participate in that market on behalf of an Existing Capacity Resource or a New Capacity Resource.

Limited Energy Resource means a Generator Asset that, due to design considerations, environmental restriction on operations, cyclical requirements, such as the need to recharge or refill or manage water flow, or fuel limitations, are unable to operate continuously at full output on a daily basis.

Load Asset means a physical load that has been registered in accordance with the Asset Registration Process. A Load Asset can be an Asset Related Demand, including a Dispatchable Asset Related Demand.

Load Management means measures (e.g., products, equipment, systems, services, practices and/or strategies) on end-use customer facilities that curtail electrical usage or shift electrical usage while delivering a comparable or acceptable level of end-use service. Such measures include, but are not limited to, energy management systems, load control end-use cycling, load curtailment strategies, and energy storage that curtails or shifts electrical usage by means other than generating electricity.

Load Shedding is the systematic reduction of system demand by temporarily decreasing load.

Load Zone is a Reliability Region, except as otherwise provided for in Section III.2.7 of Market Rule 1.

Local Area Facilities are defined in the TOA**.**

Local Benefit Upgrade(s) (LBU) is an upgrade, modification or addition to the transmission system that is: (i) rated below 115kV or (ii) rated 115kV or above and does not meet all of the non-voltage criteria for PTF classification specified in the OATT.

Local Control Centers are those control centers in existence as of the effective date of the OATT (including the CONVEX, REMVEC, Maine and New Hampshire control centers) or established by the PTOs in accordance with the TOA that are separate from the ISO Control Center and perform certain functions in accordance with the OATT and the TOA.

Local Delivery Service is the service of delivering electric energy to end users. This service is subject to state jurisdiction regardless of whether such service is provided over local distribution or transmission facilities. An entity that is an Eligible Customer under the OATT is not excused from any requirements of state law, or any order or regulation issued pursuant to state law, to arrange for Local Delivery Service with the Participating Transmission Owner and/or distribution company providing such service and to pay all applicable charges associated with such service, including charges for stranded costs and benefits.

Local Network is defined as the transmission facilities constituting a local network as identified in Attachment E, as such Attachment may be modified from time to time in accordance with the Transmission Operating Agreement.

Local Network Load is the load that a Network Customer designates for Local Network Service under Schedule 21 to the OATT.

Local Network RNS Rate is the rate applicable to Regional Network Service to effect a delivery to load in a particular Local Network, as determined in accordance with Schedule 9 to the OATT.

Local Network Service (LNS) is the network service provided under Schedule 21 and the Local Service Schedules to permit the Transmission Customer to efficiently and economically utilize its resources to serve its load.

Local Point-To-Point Service (LPTP) is Point-to-Point Service provided under Schedule 21 of the OATT and the Local Service Schedules to permit deliveries to or from an interconnection point on the PTF.

Local Public Policy Transmission Upgrade is any addition and/or upgrade to the New England Transmission System with a voltage level below 115kV that is required in connection with the construction of a Public Policy Transmission Upgrade approved for inclusion in the Regional System Plan pursuant to Attachment K to the ISO OATT or included in a Local System Plan in accordance with Appendix 1 to Attachment K.

Local Resource Adequacy Requirement is calculated pursuant to Section III.12.2.1.1.

Local Second Contingency Protection Resources are those Resources identified by the ISO on a daily basis as necessary for the provision of Operating Reserve requirements and adherence to NERC, NPCC and ISO reliability criteria over and above those Resources required to meet first contingency reliability criteria within a Reliability Region.

Local Service is transmission service provided under Schedule 21 and the Local Service Schedules thereto.

Local Service Schedule is a PTO-specific schedule to the OATT setting forth the rates, charges, terms and conditions applicable to Local Service.

Local Sourcing Requirement (LSR) is a value calculated as described in Section III.12.2.1 of Market Rule 1.

Local System Planning (LSP) is the process defined in Appendix 1 of Attachment K to the OATT.

Localized Costs are costs that the ISO, with advisory input from the Reliability Committee, determines in accordance with Schedule 12C of the OATT shall not be included in the Pool-Supported PTF costs

recoverable under this OATT, or in costs allocated to Regional Network Load according to Section 6 of Schedule 12. If there are any Localized Costs, the ISO shall identify them in the Regional System Plan.

Location is a Node, External Node, Load Zone, DRR Aggregation Zone, or Hub.

Locational Marginal Price (LMP) is defined in Section III.2 of Market Rule 1. The Locational Marginal Price for a Node is the nodal price at that Node; the Locational Marginal Price for an External Node is the nodal price at that External Node; the Locational Marginal Price for a Load Zone, DRR Aggregation Zone or Reliability Region is the Zonal Price for that Load Zone, DRR Aggregation Zone or Reliability Region, respectively; and the Locational Marginal Price for a Hub is the Hub Price for that Hub.

Long Lead Time Facility (Long Lead Facility) has the meaning specified in Section I of Schedule 22 and Schedule 25 of the OATT.

Long-Term is a term of one year or more.

Long-Term Transmission Outage is a long-term transmission outage scheduled in accordance with ISO New England Operating Procedure No. 3.

Loss Component is the component of the nodal LMP at a given Node or External Node on the PTF that reflects the cost of losses at that Node or External Node relative to the reference point. The Loss Component of the nodal LMP at a given Node on the non-PTF system reflects the relative cost of losses at that Node adjusted as required to account for losses on the non-PTF system already accounted for through tariffs associated with the non-PTF. When used in connection with Hub Price or Zonal Price, the term Loss Component refers to the Loss Components of the nodal LMPs that comprise the Hub Price or Zonal Price, which Loss Components are averaged or weighted in the same way that nodal LMPs are averaged to determine Hub Price or weighted to determine Zonal Price.

Loss of Load Expectation (LOLE) is the probability of disconnecting non-interruptible customers due to a resource deficiency.

Lost Opportunity Cost (LOC) is one of four forms of compensation that may be paid to resources providing VAR Service under Schedule 2 of the OATT.

LSE means load serving entity.

Lump Sum Blackstart Payment is defined and calculated as specified in Section 5.4 of Schedule 16 to the OATT.

Lump Sum Blackstart Capital Payment is defined and calculated as specified in Section 5.4 of Schedule 16 to the OATT.

Manual Response Rate is the rate, in MW/Minute, at which the output of a Generator Asset, or the consumption of a Dispatchable Asset Related Demand, is capable of changing.

Marginal Loss Revenue Load Obligation is defined in Section III.3.2.1(b) of Market Rule 1.

Marginal Reliability Impact is the change, with respect to an increment of capacity supply, in expected unserved energy due to resource deficiency, as measured in hours per year.

Market Credit Limit is a credit limit for a Market Participant's Financial Assurance Obligations (except FTR Financial Assurance Requirements) established for each Market Participant in accordance with Section II.C of the ISO New England Financial Assurance Policy.

Market Credit Test Percentage is calculated in accordance with Section III.B.1(a) of the ISO New England Financial Assurance Policy.

Market Efficiency Transmission Upgrade is defined as those additions and upgrades that are not related to the interconnection of a generator, and, in the ISO's determination, are designed to reduce bulk power system costs to load system-wide, where the net present value of the reduction in bulk power system costs to load system-wide exceeds the net present value of the cost of the transmission addition or upgrade. For purposes of this definition, the term "bulk power system costs to load system-wide" includes, but is not limited to, the costs of energy, capacity, reserves, losses and impacts on bilateral prices for electricity.

Market Participant is a participant in the New England Markets (including a FTR-Only Customer) that has executed a Market Participant Service Agreement, or on whose behalf an unexecuted Market Participant Service Agreement has been filed with the Commission.

Market Participant Financial Assurance Requirement is defined in Section III of the ISO New England Financial Assurance Policy.

Market Participant Obligations is defined in Section III.B.1.1 of Appendix B of Market Rule 1.

Market Participant Service Agreement (MPSA) is an agreement between the ISO and a Market Participant, in the form specified in Attachment A or Attachment A-1 to the Tariff, as applicable.

Market Rule 1 is ISO Market Rule 1 and appendices set forth in Section III of this ISO New England Inc. Transmission, Markets and Services Tariff, as it may be amended from time to time.

Market Violation is a tariff violation, violation of a Commission-approved order, rule or regulation, market manipulation, or inappropriate dispatch that creates substantial concerns regarding unnecessary market inefficiencies.

Material Adverse Change is any change in financial status including, but not limited to a downgrade to below an Investment Grade Rating by any Rating Agency, being placed on credit watch with negative implication by any Rating Agency if the Market Participant or Non-Market Participant Transmission Customer does not have an Investment Grade Rating, a bankruptcy filing or other insolvency, a report of a significant quarterly loss or decline of earnings, the resignation of key officer(s), the sanctioning of the Market Participant or Non-Market Participant Transmission Customer or any of its Principles imposed by the Federal Energy Regulatory Commission, the Securities Exchange Commission, any exchange monitored by the National Futures Association, or any state entity responsible for regulating activity in energy markets; the filing of a material lawsuit that could materially adversely impact current or future financial results; a significant change in the Market Participant's or Non-Market Participant Transmission Customer's credit default spreads; or a significant change in market capitalization.

Material Adverse Impact is defined, for purposes of review of ITC-proposed plans, as a proposed facility or project will be deemed to cause a "material adverse impact" on facilities outside of the ITC System if: (i) the proposed facility or project causes non-ITC facilities to exceed their capabilities or

exceed their thermal, voltage or stability limits, consistent with all applicable reliability criteria, or (ii) the proposed facility or project would not satisfy the standards set forth in Section I.3.9 of the Transmission, Markets and Services Tariff. This standard is intended to assure the continued service of all non-ITC firm load customers and the ability of the non-ITC systems to meet outstanding transmission service obligations.

Maximum Capacity Limit is a value calculated as described in Section III.12.2.2 of Market Rule 1.

Maximum Consumption Limit is the maximum amount, in MW, available for economic dispatch from a DARD and is based on the physical characteristics as submitted as part of the DARD's Offer Data. A Market Participant must maintain an up-to-date Maximum Consumption Limit (and where applicable, must provide the ISO with any telemetry required by ISO New England Operating Procedure No. 18 to allow the ISO to maintain an updated Maximum Consumption Limit) for all hours in which a DARD has been offered into the Day-Ahead Energy Market or Real-Time Energy Market.

Maximum Daily Energy Limit is the maximum amount of megawatt-hours that a Limited Energy Resource expects to be able to generate in the next Operating Day.

Maximum Daily Consumption Limit is the maximum amount of megawatt-hours that a Storage DARD expects to be able to consume in the next Operating Day.

Maximum Facility Load is the highest demand of an end-use customer facility since the start of the prior calendar year (or, if unavailable, an estimate thereof), where the demand evaluated is established by adding metered demand measured at the Retail Delivery Point and the output of all generators located behind the Retail Delivery Point in the same time intervals.

Maximum Interruptible Capacity is an estimate of the maximum demand reduction and Net Supply that a Demand Response Asset can deliver, as measured at the Retail Delivery Point.

Maximum Load is the highest demand since the start of the prior calendar year (or, if unavailable, an estimate thereof), as measured at the Retail Delivery Point.

Maximum Number of Daily Starts is the maximum number of times that a Binary Storage DARD or a Generator Asset can be started or that a Demand Response Resource can be interrupted in the next Operating Day under normal operating conditions.

Maximum Reduction is the maximum available demand reduction, in MW, of a Demand Response Resource that a Market Participant offers to deliver in the Day-Ahead Energy Market or Real-Time Energy Market, as reflected in the Demand Response Resource's Demand Reduction Offer.

Measure Life is the estimated time an On-Peak Demand Resource or Seasonal Peak Demand Resource measure will remain in place, or the estimated time period over which the facility, structure, equipment or system in which a measure is installed continues to exist, whichever is shorter. Suppliers of On-Peak Demand Resources or Seasonal Peak Demand Resources comprised of an aggregation of measures with varied Measures Lives shall determine and document the Measure Life either: (i) for each type of measure with a different Measure Life and adjust the aggregate performance based on the individual measure life calculation in the portfolio; or (ii) as the average Measure Life for the aggregated measures as long as the demand reduction capability of the resource is greater than or equal to the amount that cleared in the Forward Capacity Auction or reconfiguration auction for the entire Capacity Commitment Period, and the demand reduction capability for an Existing On-Peak Demand Resource or Existing Seasonal Peak Demand Resource is not over-stated in a subsequent Capacity Commitment Period. Measure Life shall be determined consistent with the resource's Measurement and Verification Plan, which shall be reviewed by the ISO to ensure consistency with the measurement and verification requirements of Market Rule 1 and the ISO New England Manuals.

Measurement and Verification Documents mean the measurement and verification documents described in Section 13.1.4.3.1 of Market Rule 1 that are submitted by On-Peak Demand Resources and Seasonal Peak Demand Resources, which include Measurement and Verification Plans, Updated Measurement and Verification Plans, Measurement and Verification Summary Reports, and Measurement and Verification Reference Reports.

Measurement and Verification Plan means the measurement and verification plan submitted by an On-Peak Demand Resource or Seasonal Peak Demand Resource as part of the qualification process for the Forward Capacity Auction pursuant to the requirements of Section III.13.1.4.3 of Market Rule 1 and the ISO New England Manuals.

Measurement and Verification Reference Reports are optional reports submitted by On-Peak Demand Resources or Seasonal Peak Demand Resources during the Capacity Commitment Period subject to the schedule in the Measurement and Verification Plan and consistent with the schedule and reporting standards set forth in the ISO New England Manuals. Measurement and Verification Reference Reports update the prospective demand reduction capability of the On-Peak Demand Resource or Seasonal Peak Demand Resource project based on measurement and verification studies performed during the Capacity Commitment Period.

Measurement and Verification Summary Report is the monthly report submitted by an On-Peak Demand Resource or Seasonal Peak Demand Resource with the monthly settlement report for the Forward Capacity Market, which documents the total demand reduction capability for all On-Peak Demand Resources and Seasonal Peak Demand Resources in operation as of the end of the previous month.

MEPCO Grandfathered Transmission Service Agreement (MGTSA) is a MEPCO long-term firm point-to-point transmission service agreement with a POR or POD at the New Brunswick border and a start date prior to June 1, 2007 where the holder has elected, by written notice delivered to MEPCO within five (5) days following the filing of the settlement agreement in Docket Nos. ER07-1289 and EL08-56 or by September 1, 2008 (whichever is later), MGTSA treatment as further described in Section II.45.1.

Merchant Transmission Facilities (MTF) are the transmission facilities owned by MTOs, defined and classified as MTF pursuant to Schedule 18 of the OATT, over which the ISO shall exercise Operating Authority in accordance with the terms set forth in a MTOA or Attachment K to the OATT, rated 69 kV or above and required to allow energy from significant power sources to move freely on the New England Transmission System.

Merchant Transmission Facilities Provider (MTF Provider) is an entity as defined in Schedule 18 of the OATT.

Merchant Transmission Facilities Service (MTF Service) is transmission service over MTF as provided for in Schedule 18 of the OATT.

Merchant Transmission Operating Agreement (MTOA) is an agreement between the ISO and an MTO with respect to its MTF.

Merchant Transmission Owner (MTO) is an owner of MTF.

Meter Data Error means an error in meter data, including an error in Coincident Peak Contribution values, on an Invoice issued by the ISO after the completion of the Data Reconciliation Process as described in the ISO New England Manuals and in Section III.3.8 of Market Rule 1.

Meter Data Error RBA Submission Limit means the date thirty 30 calendar days after the issuance of the Invoice containing the results of the Data Reconciliation Process as described in the ISO New England Manuals and in Section III.3.6 of Market Rule 1.

Metered Quantity For Settlement is defined in Section III.3.2.1.1 of Market Rule 1.

Minimum Consumption Limit is (a) the lowest consumption level, in MW, available for economic dispatch from a DARD and is based on the physical characteristics as submitted as part of the DARD's Offer Data, and (b) for a DARD undergoing Facility and Equipment Testing or auditing, the level to which the DARD requests and is approved to operate or is directed to operate for purposes of completing the Facility and Equipment Testing or auditing.

Minimum Down Time is the number of hours that must elapse after a Generator Asset or Storage DARD has been released for shutdown at or below its Economic Minimum Limit or Minimum Consumption Limit before the Generator Asset or Storage DARD can be brought online and be released for dispatch at its Economic Minimum Limit or Minimum Consumption Limit.

Minimum Generation Emergency means an Emergency declared by the ISO in which the ISO anticipates requesting one or more Generator Assets to operate at or below Economic Minimum Limit in order to manage, alleviate, or end the Emergency.

Minimum Generation Emergency Credits are those Real-Time Dispatch NCPC Credits calculated pursuant to Appendix F of Market Rule 1 for resources within a reliability region that are dispatched during a period for which a Minimum Generation Emergency has been declared.

Minimum Reduction is the minimum available demand reduction, in MW, of a Demand Response Resource that a Market Participant offers to deliver in the Day-Ahead Energy Market or Real-Time Energy Market, as reflected in the Demand Response Resource's Demand Reduction Offer.

Minimum Reduction Time is the minimum number of hours of demand reduction at or above the Minimum Reduction for which the ISO must dispatch a Demand Response Resource to reduce demand.

Minimum Run Time is the number of hours that a Generator Asset must remain online after it has been scheduled to reach its Economic Minimum Limit before it can be released for shutdown from its Economic Minimum Limit or the number of hours that must elapse after a Storage DARD has been scheduled to consume at its Minimum Consumption Limit before it can be released for shutdown.

Minimum Time Between Reductions is the number of hours that must elapse after a Demand Response Resource has received a Dispatch Instruction to stop reducing demand before the Demand Response Resource can achieve its Minimum Reduction after receiving a Dispatch Instruction to start reducing demand.

Minimum Total Reserve Requirement, which does not include Replacement Reserve, is the combined amount of TMSR, TMNSR, and TMOR required system-wide as described in Section III.2.7A and ISO New England Operating Procedure No. 8.

Monthly Blackstart Service Charge is the charge made to Transmission Customers pursuant to Section 6 of Schedule 16 to the OATT.

Monthly Capacity Payment is the Forward Capacity Market payment described in Section III.13.7.3 of Market Rule 1.

Monthly Peak is defined in Section II.21.2 of the OATT.

Monthly PER is calculated in accordance with Section III.13.7.1.2.2 of Market Rule 1.

Monthly Real-Time Demand Reduction Obligation is the absolute value of a Customer's hourly Real-Time Demand Reduction Obligation summed for all hours in a month, in MWhs.

Monthly Real-Time Generation Obligation is the sum, for all hours in a month, at all Locations, of a Customer's Real-Time Generation Obligation, in MWhs.

Monthly Real-Time Load Obligation is the absolute value of a Customer's hourly Real-Time Load Obligation summed for all hours in a month, in MWhs.

Monthly Regional Network Load is defined in Section II.21.2 of the OATT.

Monthly Statement is the first weekly Statement issued on a Monday after the tenth of a calendar month that includes both the Hourly Charges for the relevant billing period and Non-Hourly Charges for the immediately preceding calendar month.

MRI Transition Period is the period specified in Section III.13.2.2.1.

MUI is the market user interface.

Municipal Market Participant is defined in Section II of the ISO New England Financial Assurance Policy.

MW is megawatt.

MWh is megawatt-hour.

Native Load Customers are the wholesale and retail power customers of a Transmission Owner on whose behalf the Transmission Owner, by statute, franchise, regulatory requirement, or contract, has undertaken an obligation to construct and operate its system to meet the reliable electric needs of such customers.

NCPC Charge means the charges to Market Participants calculated pursuant to Appendix F to Market Rule 1.

NCPC Credit means the credits to Market Participants calculated pursuant to Appendix F to Market Rule 1.

Needs Assessment is defined in Section 4.1 of Attachment K to the OATT.

NEMA, for purposes of Section III of the Tariff, is the Northeast Massachusetts Reliability Region.

NEMA Contract is a contract described in Appendix C of Market Rule 1 and listed in Exhibit 1 of Appendix C of Market Rule 1.

NEMA Load Serving Entity (NEMA LSE) is a Transmission Customer or Congestion Paying LSE Entity that serves load within NEMA.

NEMA or Northeast Massachusetts Upgrade, for purposes of Section II of the Tariff, is an addition to or modification of the PTF into or within the Northeast Massachusetts Reliability Region that was not, as of December 31, 1999, the subject of a System Impact Study or application filed pursuant to Section I.3.9 of the Transmission, Markets and Services Tariff; that is not related to generation interconnections; and that will be completed and placed in service by June 30, 2004. Such upgrades include, but are not limited to, new transmission facilities and related equipment and/or modifications to existing transmission facilities and related equipment. The list of NEMA Upgrades is contained in Schedule 12A of the OATT.

NEPOOL is the New England Power Pool, and the entities that collectively participated in the New England Power Pool.

NEPOOL Agreement is the agreement among the participants in NEPOOL.

NEPOOL GIS is the generation information system.

NEPOOL GIS Administrator is the entity or entities that develop, administer, operate and maintain the NEPOOL GIS.

NEPOOL GIS API Fees are the one-time on-boarding fees and annual maintenance fees charged to NEPOOL by the NEPOOL GIS Administrator for each NEPOOL Participant or Market Participant that accesses the NEPOOL GIS through an application programming interface pursuant to Rule 3.9(b) of the operating rules of the NEPOOL GIS.

NEPOOL Participant is a party to the NEPOOL Agreement.

NERC is the North American Electric Reliability Corporation or its successor organization.

NESCOE is the New England States Committee on Electricity, recognized by the Commission as the regional state committee for the New England Control Area.

Net Commitment Period Compensation (NCPC) is the compensation methodology for Resources that is described in Appendix F to Market Rule 1.

Net CONE is an estimate of the Cost of New Entry, net of the first-year non-capacity market revenues, for a reference technology resource type and is intended to equal the amount of capacity revenue the reference technology resource would require, in its first year of operation, to be economically viable given reasonable expectations of the first year energy and ancillary services revenues, and projected revenue for subsequent years.

Net Regional Clearing Price is described in Section III.13.7.5 of Market Rule 1.

Net Supply is energy injected into the transmission or distribution system at a Retail Delivery Point.

Net Supply Capability is the maximum Net Supply a facility is physically and contractually able to inject into the transmission or distribution system at its Retail Delivery Point.

Network Capability Interconnection Standard has the meaning specified in Section I of Schedule 22, Attachment 1 to Schedule 23, and Section I of Schedule 25 of the OATT.

Network Customer is a Transmission Customer receiving RNS or LNS.

Network Import Capability (NI Capability) is defined in Section I of Schedule 25 of the OATT.

Network Import Interconnection Service (NI Interconnection Service) is defined in Section I of Schedule 25 of the OATT.

Network Resource is defined as follows: (1) With respect to Market Participants, (a) any generating resource located in the New England Control Area which has been placed in service prior to the

Compliance Effective Date (including a unit that has lost its capacity value when its capacity value is restored and a deactivated unit which may be reactivated without satisfying the requirements of Section II.46 of the OATT in accordance with the provisions thereof) until retired; (b) any generating resource located in the New England Control Area which is placed in service after the Compliance Effective Date until retired, provided that (i) the Generator Owner has complied with the requirements of Sections II.46 and II.47 and Schedules 22 and 23 of the OATT, and (ii) the output of the unit shall be limited in accordance with Sections II.46 and II.47 and Schedules 22 and 23, if required; and (c) any generating resource or combination of resources (including bilateral purchases) located outside the New England Control Area for so long as any Market Participant has an Ownership Share in the resource or resources which is being delivered to it in the New England Control Area to serve Regional Network Load located in the New England Control Area or other designated Regional Network Loads contemplated by Section II.18.3 of the OATT taking Regional Network Service. (2) With respect to Non-Market Participant Transmission Customers, any generating resource owned, purchased or leased by the Non-Market Participant Transmission Customer which it designates to serve Regional Network Load.

New Brunswick Security Energy is defined in Section III.3.2.6A of Market Rule 1.

New Capacity Offer is an offer in the Forward Capacity Auction to provide capacity from a New Generating Capacity Resource, New Import Capacity Resource or New Demand Capacity Resource.

New Capacity Qualification Deadline is a deadline, specified in Section III.13.1.10 of Market Rule 1, for submission of certain qualification materials for the Forward Capacity Auction, as discussed in Section III.13.1 of Market Rule 1.

New Capacity Qualification Package is information submitted by certain new resources prior to participation in the Forward Capacity Auction, as described in Section III.13.1 of Market Rule 1.

New Capacity Resource is a resource (i) that never previously received any payment as a capacity resource including any capacity payment pursuant to the market rules in effect prior to June 1, 2010 and that has not cleared in any previous Forward Capacity Auction; or (ii) that is otherwise eligible to participate in the Forward Capacity Auction as a New Capacity Resource.

New Capacity Show of Interest Form is described in Section III.13.1.1.2.1 of Market Rule 1.

New Capacity Show of Interest Submission Window is the period of time during which a Project Sponsor may submit a New Capacity Show of Interest Form or a New Demand Capacity Resource Show of Interest Form, as described in Section III.13.1.10 of Market Rule 1.

New Demand Capacity Resource is a type of Demand Capacity Resource participating in the Forward Capacity Market, as defined in Section III.13.1.4.1 of Market Rule 1.

New Demand Capacity Resource Qualification Package is the information that a Project Sponsor must submit, in accordance with Section III.13.1.4.1.1.2 of Market Rule 1, for each resource that it seeks to offer in the Forward Capacity Auction as a New Demand Capacity Resource.

New Demand Capacity Resource Show of Interest Form is described in Section III.13.1.4.1.1.1 of Market Rule 1.

New England Control Area is the Control Area for New England, which includes PTF, Non-PTF, MTF and OTF. The New England Control Area covers Connecticut, Rhode Island, Massachusetts, New Hampshire, Vermont, and part of Maine (i.e., excluding the portions of Northern Maine and the northern portion of Eastern Maine which are in the Maritimes Control Area).

New England Markets are markets or programs for the purchase of energy, capacity, ancillary services, demand response services or other related products or services (including Financial Transmission Rights) that are delivered through or useful to the operation of the New England Transmission System and that are administered by the ISO pursuant to rules, rates, or agreements on file from time to time with the Federal Energy Regulatory Commission.

New England System Restoration Plan is the plan that is developed by ISO, in accordance with NERC Reliability Standards, NPCC regional criteria and standards, ISO New England Operating Documents and ISO operating agreements, to facilitate the restoration of the New England Transmission System following a partial or complete shutdown of the New England Transmission System.

New England Transmission System is the system of transmission facilities, including PTF, Non-PTF, OTF and MTF, within the New England Control Area under the ISO's operational jurisdiction.

New Generating Capacity Resource is a type of resource participating in the Forward Capacity Market, as described in Section III.13.1.1.1 of Market Rule 1.

New Import Capacity Resource is a type of resource participating in the Forward Capacity Market, as defined in Section III.13.1.3.4 of Market Rule 1.

New Resource Offer Floor Price is defined in Section III.A.21.2.

NMPTC means Non-Market Participant Transmission Customer.

NMPTC Credit Threshold is described in Section V.A.2 of the ISO New England Financial Assurance Policy.

NMPTC Financial Assurance Requirement is an amount of additional financial assurance for Non-Market Participant Transmission Customers described in Section V.D of the ISO New England Financial Assurance Policy.

Node is a point on the New England Transmission System at which LMPs are calculated.

No-Load Fee is the amount, in dollars per hour, for a Generator Asset that must be paid to Market Participants with an Ownership Share in the Generator Asset for being scheduled in the New England Markets, in addition to the Start-Up Fee and price offered to supply energy, for each hour that the Generator Asset is scheduled in the New England Markets.

Nominated Consumption Limit is the consumption level specified by the Market Participant for a Dispatchable Asset Related Demand as adjusted in accordance with the provisions of Section III.13.7.5.1.3.

Non-Commercial Capacity is the capacity of a New Capacity Resource or an Existing Capacity Resource, or portion thereof, that has not achieved FCM Commercial Operation.

Non-Commercial Capacity Cure Period is the time period described in Section VII.D of the ISO New England Financial Assurance Policy.

Non-Commercial Capacity Financial Assurance Amount (Non-Commercial Capacity FA Amount) is the financial assurance amount held on Non-Commercial Capacity cleared in a Forward Capacity Auction as calculated in accordance with Section VII.B.2 of the ISO New England Financial Assurance Policy.

Non-Designated Blackstart Resource Study Cost Payments are the study costs reimbursed under Section 5.3 of Schedule 16 of the OATT.

Non-Dispatchable Resource is any Resource that does not meet the requirements to be a Dispatchable Resource.

Non-Hourly Charges are defined in Section 1.3 of the ISO New England Billing Policy.

Non-Hourly Requirements are determined in accordance with Section III.A(ii) of the ISO New England Financial Assurance Policy, which is Exhibit 1A of Section I of the Tariff.

Non-Incumbent Transmission Developer is a Qualified Transmission Project Sponsor that: (i) is not currently a PTO; (ii) has a transmission project listed in the RSP Project List; and (iii) has executed a Non-Incumbent Transmission Developer Operating Agreement. "Non-Incumbent Transmission Developer" also includes a PTO that proposes the development of a transmission facility not located within or connected to its existing electric system; however, because such a PTO is a party to the TOA, it is not required to enter into a Non-Incumbent Transmission Developer Operating Agreement.

Non-Incumbent Transmission Developer Operating Agreement (or NTDOA) is an agreement between the ISO and a Non-Incumbent Transmission Developer in the form specified in Attachment O to the OATT that sets forth their respective rights and responsibilities to each other with regard to proposals for and construction of certain transmission facilities.

Non-Market Participant is any entity that is not a Market Participant.

Non-Market Participant Transmission Customer is any entity which is not a Market Participant but is a Transmission Customer.

Non-Municipal Market Participant is defined in Section II of the ISO New England Financial Assurance Policy.

Non-PTF Transmission Facilities (Non-PTF) are the transmission facilities owned by the PTOs that do not constitute PTF, OTF or MTF.

Non-Qualifying means a Market Participant that is not a Credit Qualifying Market Participant.

Notice of RBA is defined in Section 6.3.2 of the ISO New England Billing Policy.

Notification Time is the time required for a Generator Asset to synchronize to the system from the time a startup Dispatch Instruction is received from the ISO.

Northeastern Planning Protocol is the Amended and Restated Northeastern ISO/RTO Planning Coordination Protocol on file with the Commission and posted on the ISO website at the following URL: www.iso-ne.com/static-assets/documents/2015/07/northeastern_protocol_dmeast.doc.

NPCC is the Northeast Power Coordinating Council.

Obligation Month means a time period of one calendar month for which capacity payments are issued and the costs associated with capacity payments are allocated.

Offer Data means the scheduling, operations planning, dispatch, new Resource, and other data, including Generator Asset, Dispatchable Asset Related Demand, and Demand Response Resource operating limits based on physical characteristics, and information necessary to schedule and dispatch Generator Assets, Dispatchable Asset Related Demands, and Demand Response Resources for the provision or consumption of energy, the provision of other services, and the maintenance of the reliability and security of the transmission system in the New England Control Area, and specified for submission to the New England Markets for such purposes by the ISO.

Offered CLAIM10 is a Supply Offer value or a Demand Reduction Offer value between 0 and the CLAIM10 of the resource that represents the amount of TMNSR available either from an off-line Fast Start Generator or from a Fast Start Demand Response Resource that has not been dispatched.

Offered CLAIM30 is a Supply Offer value or a Demand Reduction Offer value between 0 and the CLAIM30 of the resource that represents the amount of TMOR available either from an off-line Fast Start Generator or from a Fast Start Demand Response Resource that has not been dispatched.

On-Peak Demand Resource is a type of Demand Capacity Resource and means installed measures (e.g., products, equipment, systems, services, practices and/or strategies) on end-use customer facilities that reduce the total amount of electrical energy consumed during Demand Resource On-Peak Hours, while delivering a comparable or acceptable level of end-use service. Such measures include Energy Efficiency, Load Management, and Distributed Generation.

Open Access Same-Time Information System (OASIS) is the ISO information system and standards of conduct responding to requirements of 18 C.F.R. §37 of the Commission's regulations and all additional requirements implemented by subsequent Commission orders dealing with OASIS.

Open Access Transmission Tariff (OATT) is Section II of the ISO New England Inc. Transmission, Markets and Services Tariff.

Operating Authority is defined pursuant to a MTOA, an OTOA, the TOA or the OATT, as applicable.

Operating Data means GADS Data, data equivalent to GADS Data, CARL Data, metered load data, or actual system failure occurrences data, all as described in the ISO New England Operating Procedures.

Operating Day means the calendar day period beginning at midnight for which transactions on the New England Markets are scheduled.

Operating Reserve means Ten-Minute Spinning Reserve (TMSR), Ten-Minute Non-Spinning Reserve (TMNSR) and Thirty-Minute Operating Reserve (TMOR).

Operations Date is February 1, 2005.

OTF Service is transmission service over OTF as provided for in Schedule 20.

Other Transmission Facility (OTF) are the transmission facilities owned by Transmission Owners, defined and classified as OTF pursuant to Schedule 20, over which the ISO shall exercise Operating

Authority in accordance with the terms set forth in the OTOA, rated 69 kV or above, and required to allow energy from significant power sources to move freely on the New England Transmission System. OTF classification shall be limited to the Phase I/II HVDC-TF.

Other Transmission Operating Agreements (OTOA) is the agreement(s) between the ISO, an OTO and/or the associated service provider(s) with respect to an OTF, which includes the HVDC Transmission Operating Agreement and the Phase I/II HVDC-TF Transmission Service Administration Agreement. With respect to the Phase I/II HVDC-TF, the HVDC Transmission Operating Agreement covers the rights and responsibilities for the operation of the facility and the Phase I/II HVDC-TF Transmission Service Administration Agreement covers the rights and responsibilities for the administration of transmission service.

Other Transmission Owner (OTO) is an owner of OTF.

Ownership Share is a right or obligation, for purposes of settlement, to a percentage share of all credits or charges associated with a Generator Asset or a Load Asset, where such facility is interconnected to the New England Transmission System.

Participant Expenses are defined in Section 1 of the Participants Agreement.

Participant Required Balance is defined in Section 5.3 of the ISO New England Billing Policy.

Participant Vote is defined in Section 1 of the Participants Agreement.

Participants Agreement is the agreement among the ISO, the New England Power Pool and Individual Participants, as amended from time to time, on file with the Commission.

Participants Committee is the principal committee referred to in the Participants Agreement.

Participating Transmission Owner (PTO) is a transmission owner that is a party to the TOA.

Passive DR Audit is the audit performed pursuant to Section III.13.6.1.5.4.

Passive DR Auditing Period is the summer Passive DR Auditing Period (June 1 to August 31) or winter Passive DR Auditing Period (December 1 to January 31) applicable to On-Peak Demand Resources and Seasonal Peak Demand Resources.

Payment is a sum of money due to a Covered Entity from the ISO.

Payment Default Shortfall Fund is defined in Section 5.1 of the ISO New England Billing Policy.

Peak Energy Rent (PER) is described in Section III.13.7.1.2 of Market Rule 1.

PER Proxy Unit is described in Section III.13.7.1.2.1 of Market Rule 1.

Permanent De-list Bid is a bid that may be submitted by an Existing Generating Capacity Resource, Existing Import Capacity Resource, or Existing Demand Capacity Resource in the Forward Capacity Auction to permanently remove itself from the capacity market, as described in Section III.13.1.2.3.1.5 of Market Rule 1.

Phase I Transfer Credit is 40% of the HQICC, or such other fraction of the HQICC as the ISO may establish.

Phase I/II HVDC-TF is defined in Schedule 20A to Section II of this Tariff.

Phase I/II HVDC-TF Transfer Capability is the transfer capacity of the Phase I/II HVDC-TF under normal operating conditions, as determined in accordance with Good Utility Practice. The “Phase I Transfer Capability” is the transfer capacity under normal operating conditions, as determined in accordance with Good Utility Practice, of the Phase I terminal facilities as determined initially as of the time immediately prior to Phase II of the Phase I/II HVDC-TF first being placed in service, and as adjusted thereafter only to take into account changes in the transfer capacity which are independent of any effect of Phase II on the operation of Phase I. The “Phase II Transfer Capability” is the difference between the Phase I/II HVDC-TF Transfer Capability and the Phase I Transfer Capability. Determinations of, and any adjustment in, Phase I/II HVDC-TF Transfer Capability shall be made by the ISO, and the basis for any such adjustment shall be explained in writing and posted on the ISO website.

Phase One Proposal is a first round submission, as defined in Section 4.3 of Attachment K of the OATT, of a proposal for a Reliability Transmission Upgrade or Market Efficiency Transmission Upgrade, as applicable, by a Qualified Transmission Project Sponsor.

Phase II Transfer Credit is 60% of the HQICC, or such other fraction of the HQICC as the ISO may establish.

Phase Two Solution is a second round submission, as defined in Section 4.3 of Attachment K of the OATT, of a proposal for a Reliability Transmission Upgrade or Market Efficiency Transmission Upgrade by a Qualified Transmission Project Sponsor.

Planning Advisory Committee is the committee described in Attachment K of the OATT.

Planning and Reliability Criteria is defined in Section 3.3 of Attachment K to the OATT.

Planning Authority is an entity defined as such by the North American Electric Reliability Corporation.

Point(s) of Delivery (POD) is point(s) of interconnection where capacity and/or energy transmitted by a Transmission Customer will be made available to the Receiving Party under the OATT.

Point of Interconnection shall have the same meaning as that used for purposes of Schedules 22, 23 and 25 of the OATT.

Point(s) of Receipt (POR) is point(s) of interconnection where capacity and/or energy transmitted by a Transmission Customer will be made available by the Delivering Party under the OATT.

Point-To-Point Service is the transmission of capacity and/or energy on either a firm or non-firm basis from the Point(s) of Receipt to the Point(s) of Delivery under the OATT pursuant to Local Point-To-Point Service or OTF Service or MTF Service; and the transmission of capacity and/or energy from the Point(s) of Receipt to the Point(s) of Delivery under the OATT pursuant to Through or Out Service.

Pool-Planned Unit is one of the following units: New Haven Harbor Unit 1 (Coke Works), Mystic Unit 7, Canal Unit 2, Potter Unit 2, Wyman Unit 4, Stony Brook Units 1, 1A, 1B, 1C, 2A and 2B, Millstone

Unit 3, Seabrook Unit 1 and Waters River Unit 2 (to the extent of 7 megawatts of its Summer capability and 12 megawatts of its Winter capability).

Pool PTF Rate is the transmission rate determined in accordance with Schedule 8 to the OATT.

Pool RNS Rate is the transmission rate determined in accordance with paragraph (2) of Schedule 9 of Section II of the Tariff.

Pool-Scheduled Resources are described in Section III.1.10.2 of Market Rule 1.

Pool Supported PTF is defined as: (i) PTF first placed in service prior to January 1, 2000; (ii) Generator Interconnection Related Upgrades with respect to Category A and B projects (as defined in Schedule 11), but only to the extent not paid for by the interconnecting Generator Owner; and (iii) other PTF upgrades, but only to the extent the costs therefore are determined to be Pool Supported PTF in accordance with Schedule 12.

Pool Transmission Facility (PTF) means the transmission facilities owned by PTOs which meet the criteria specified in Section II.49 of the OATT.

Posting Entity is any Market Participant or Non-Market Participant Transmission Customer providing financial security under the provisions of the ISO New England Financial Assurance Policy.

Posture means an action of the ISO to deviate from the jointly optimized security constrained economic dispatch for Energy and Operating Reserves solution for a Resource produced by the ISO’s technical software for the purpose of maintaining sufficient Operating Reserve (both online and off-line) or for the provision of voltage or VAR support.

Posturing Credits are the Real-Time Posturing NCPC Credits for Generators (Other Than Limited Energy Resources) Postured for Reliability and the Real-Time Posturing NCPC Credit for Limited Energy Resources Postured for Reliability.

Power Purchaser is the entity that is purchasing the capacity and/or energy to be transmitted under the OATT.

Principal is (i) the sole proprietor of a sole proprietorship; (ii) a general partner of a partnership; (iii) a president, chief executive officer, chief operating officer or chief financial officer (or equivalent position) of an organization; (iv) a manager, managing member or a member vested with the management authority for a limited liability company or limited liability partnership; (v) any person or entity that has the power to exercise a controlling influence over an organization's activities that are subject to regulation by the Federal Energy Regulatory Commission, the Securities and Exchange Commission, the Commodity Futures Trading Commission, any exchange monitored by the National Futures Association, or any state entity responsible for regulating activity in energy markets; or (vi) any person or entity that: (a) is the direct owner of 10% or more of any class of an organization's equity securities; or (b) has directly contributed 10% or more of an organization's capital.

Profiled Load Assets include all Load Assets that are not directly metered by OP-18 compliant metering as currently described in Section IV (Metering and Recording for Settlements) of OP18, and some Load Assets that are measured by OP-18 compliant metering (as currently described in Section IV of OP-18) to which the Host Participant Assigned Meter Reader allocates non-PTF losses.

Project Sponsor is an entity seeking to have a New Generating Capacity Resource, New Import Capacity Resource or New Demand Capacity Resource participate in the Forward Capacity Market, as described in Section III.13.

Proxy De-List Bid is a type of bid used in the Forward Capacity Market.

Provisional Member is defined in Section I.68A of the Restated NEPOOL Agreement.

PTO Administrative Committee is the committee referred to in Section 11.04 of the TOA.

Public Policy Requirement is a requirement reflected in a statute enacted by, or a regulation promulgated by, the federal government or a state or local (e.g., municipal or county) government.

Public Policy Transmission Study is a study conducted by the ISO pursuant to the process set out in Section 4A.3 of Attachment K of the OATT, and consists of two phases: (i) an initial phase to produce a rough estimate of the costs and benefits of concepts that could meet transmission needs driven by public policy requirements; and (ii) a follow-on phase designed to produce more detailed analysis and engineering work on transmission concepts identified in the first phase.

Public Policy Local Transmission Study is a study conducted by a PTO pursuant to the process set out in Section 1.6 of Attachment K Appendix 1 of the OATT, and consists of two phases: (i) an initial phase to produce an estimate of the costs and benefits of concepts that could meet transmission needs driven by public policy requirements; and (ii) a follow-on phase designed to produce more detailed analysis and engineering work on transmission concepts identified in the first phase.

Public Policy Transmission Upgrade is an addition and/or upgrade to the New England Transmission System that meets the voltage and non-voltage criteria for Public Policy Transmission Upgrade PTF classification specified in the OATT, and has been included in the Regional System Plan and RSP Project List as a Public Policy Transmission Upgrade pursuant to the procedures described in Section 4A of Attachment K of the OATT.

Publicly Owned Entity is defined in Section I of the Restated NEPOOL Agreement.

Qualification Process Cost Reimbursement Deposit is described in Section III.13.1.9.3 of Market Rule 1.

Qualified Capacity is the amount of capacity a resource may provide in the summer or winter in a Capacity Commitment Period, as determined in the Forward Capacity Market qualification processes.

Qualified Generator Reactive Resource(s) is any generator source of dynamic reactive power that meets the criteria specified in Schedule 2 of the OATT.

Qualified Non-Generator Reactive Resource(s) is any non-generator source of dynamic reactive power that meets the criteria specified in Schedule 2 of the OATT.

Qualified Reactive Resource(s) is any Qualified Generator Reactive Resource and/or Qualified Non-Generator Reactive Resource that meets the criteria specified in Schedule 2 of the OATT.

Qualified Transmission Project Sponsor is defined in Sections 4B.2 and 4B.3 of Attachment K of the OATT.

Queue Position has the meaning specified in Section I of Schedule 22, Attachment 1 to Schedule 23, and Section I of Schedule 25 of the OATT.

Rapid Response Pricing Asset is: (i) a Fast Start Generator; (ii) a Flexible DNE Dispatchable Generator; or (iii) a Binary Storage DARD with Offer Data specifying a Minimum Run Time and a Minimum Down Time not exceeding one hour each. A Rapid Response Pricing Asset shall also include a Fast Start Demand Response Resource for which the Market Participant's Offer Data meets the following criteria: (i) Minimum Reduction Time does not exceed one hour; and (ii) Demand Response Resource Notification Time plus Demand Response Resource Start-Up Time does not exceed 30 minutes.

Rapid Response Pricing Opportunity Cost is the NCPC Credit described in Section III.F.2.3.10.

Rated means a Market Participant that receives a credit rating from one or more of the Rating Agencies, or, if such Market Participant is not rated by one of the Rating Agencies, then a Market Participant that has outstanding unsecured debt rated by one or more of the Rating Agencies.

Rating Agencies are Standard and Poor's (S&P), Moody's, and Fitch.

Rationing Minimum Limit is the MW quantity for a New Generating Capacity Resource or Existing Generating Capacity Resource below which n offer or bid may not be rationed in the Forward Capacity Auction, but shall not apply to supply offers or demand bids in a substitution auction as specified in Section III.13.2.8.2 and Section III.13.2.8.3.

RBA Decision is a written decision provided by the ISO to a Disputing Party and to the Chair of the NEPOOL Budget and Finance Subcommittee accepting or denying a Requested Billing Adjustment within twenty Business Days of the date the ISO distributes a Notice of RBA, unless some later date is agreed upon by the Disputing Party and the ISO.

Reactive Capability Audit is an audit that measures the ability of a Reactive Resource to provide or absorb reactive power to or from the transmission system at a specified real power output or consumption.

Reactive Resource is a device that dynamically adjusts reactive power output automatically in Real-Time over a continuous range, taking into account control system response bandwidth, within a specified voltage bandwidth in response to grid voltage changes. These resources operate to maintain a set-point

voltage and include, but are not limited to, Generator Assets, Dispatchable Asset Related Demands that are part of an Electric Storage Facility, and dynamic transmission devices.

Reactive Supply and Voltage Control Service is the form of Ancillary Service described in Schedule 2 of the OATT.

Real-Time is a period in the current Operating Day for which the ISO dispatches Resources for energy and Regulation, designates Resources for Regulation and Operating Reserve and, if necessary, commits additional Resources.

Real-Time Adjusted Load Obligation is defined in Section III.3.2.1(b) of Market Rule 1.

Real-Time Adjusted Load Obligation Deviation is defined in Section III.3.2.1(d) of Market Rule 1.

Real-Time Commitment NCPC Credit is an NCPC Credit calculated pursuant to Appendix F to Market Rule 1.

Real-Time Congestion Revenue is defined in Section III.3.2.1(i) of Market Rule 1.

Real-Time Demand Reduction Obligation is defined in Section III.3.2.1(c) of Market Rule 1.

Real-Time Demand Reduction Obligation Deviation is defined in Section III.3.2.1(e) of Market Rule 1.

Real-Time Dispatch NCPC Credit is an NCPC Credit calculated pursuant to Appendix F to Market Rule 1.

Real-Time Energy Inventory is a component of the spot payment that a Market Participant may receive through the inventoried energy program, as described in Section III.K.3.2.1 of Market Rule 1.

Real-Time Energy Market means the purchase or sale of energy, purchase of demand reductions, payment of Congestion Costs, and payment for losses for quantity deviations from the Day-Ahead Energy Market in the Operating Day and designation of and payment for provision of Operating Reserve in Real-Time.

Real-Time Energy Market Deviation Congestion Charge/Credit is defined in Section III.3.2.1(g) of Market Rule 1.

Real-Time Energy Market Deviation Energy Charge/Credit is defined in Section III.3.2.1(g) of Market Rule 1.

Real-Time Energy Market Deviation Loss Charge/Credit is defined in Section III.3.2.1(g) of Market Rule 1.

Real-Time Energy Market NCPC Credits are the Real-Time Commitment NCPC Credit and the Real-Time Dispatch NCPC Credit.

Real-Time External Transaction NCPC Credit is an NCPC Credit calculated pursuant to Appendix F to Market Rule 1.

Real-Time Generation Obligation is defined in Section III.3.2.1(b) of Market Rule 1.

Real-Time Generation Obligation Deviation is defined in Section III.3.2.1(d) of Market Rule 1.

Real-Time High Operating Limit is the maximum output, in MW, of a Generator Asset that could be achieved, consistent with Good Utility Practice, in response to an ISO request for Energy (including pursuant to Section III.13.6.4 of Market Rule 1), for each hour of the Operating Day, as reflected in the Generator Asset's Offer Data. This value is based on real-time operating conditions and the physical operating characteristics and operating permits of the facility and must be submitted for all Generator Assets (other than Settlement Only Resources).

Real-Time Load Obligation is defined in Section III.3.2.1(b) of Market Rule 1.

Real-Time Load Obligation Deviation is defined in Section III.3.2.1(d) of Market Rule 1.

Real-Time Locational Adjusted Net Interchange is defined in Section III.3.2.1(b) of Market Rule 1.

Real-Time Locational Adjusted Net Interchange Deviation is defined in Section III.3.2.1(d) of Market Rule 1.

Real-Time Loss Revenue is defined in Section III.3.2.1(l) of Market Rule 1.

Real-Time Loss Revenue Charges or Credits are defined in Section III.3.2.1(m) of Market Rule 1.

Real-Time NCP Load Obligation is the maximum hourly value, during a month, of a Market Participant's Real-Time Load Obligation summed over all Locations, excluding exports, in kilowatts.

Real-Time Offer Change is a modification to a Supply Offer pursuant to Section III.1.10.9(b).

Real-Time Posturing NCPC Credit for Generators (Other Than Limited Energy Resources) Postured for Reliability is an NCPC Credit calculated pursuant to Appendix F to Market Rule 1.

Real-Time Posturing NCPC Credit for Limited Energy Resources Postured for Reliability is an NCPC Credit calculated pursuant to Appendix F to Market Rule 1.

Real-Time Prices means the Locational Marginal Prices resulting from the ISO's dispatch of the New England Markets in the Operating Day.

Real-Time Reserve Charge is a Market Participant's share of applicable system and Reserve Zone Real-Time Operating Reserve costs attributable to meeting the Real-Time Operating Reserve requirement as calculated in accordance with Section III.10 of Market Rule 1.

Real-Time Reserve Clearing Price is the Real-Time TMSR, TMNSR or TMOR clearing price, as applicable, for the system and each Reserve Zone that is calculated in accordance with Section III.2.7A of Market Rule 1.

Real-Time Reserve Credit is a Market Participant's compensation associated with that Market Participant's Resources' Reserve Quantity For Settlement as calculated in accordance with Section III.10 of Market Rule 1.

Real-Time Reserve Designation is the amount, in MW, of Operating Reserve designated to a Resource in Real-Time by the ISO as described in Section III.1.7.19 of Market Rule 1.

Real-Time Reserve Opportunity Cost is defined in Section III.2.7A(b) of Market Rule 1.

Real-Time Synchronous Condensing NCPC Credit is an NCPC Credit calculated pursuant to Appendix F to Market Rule 1.

Real-Time System Adjusted Net Interchange means, for each hour, the sum of Real-Time Locational Adjusted Net Interchange for a Market Participant over all Locations, in kilowatts.

Receiving Party is the entity receiving the capacity and/or energy transmitted to Point(s) of Delivery under the OATT.

Reference Level is defined in Section III.A.5.7 of Appendix A of Market Rule 1.

Regional Benefit Upgrade(s) (RBU) means a Transmission Upgrade that: (i) is rated 115kV or above; (ii) meets all of the non-voltage criteria for PTF classification specified in the OATT; and (iii) is included in the Regional System Plan as either a Reliability Transmission Upgrade or a Market Efficiency Transmission Upgrade identified as needed pursuant to Attachment K of the OATT. The category of RBU shall not include any Transmission Upgrade that has been categorized under any of the other categories specified in Schedule 12 of the OATT (e.g., an Elective Transmission Upgrade shall not also be categorized as an RBU). Any upgrades to transmission facilities rated below 115kV that were PTF prior to January 1, 2004 shall remain classified as PTF and be categorized as an RBU if, and for so long as, such upgrades meet the criteria for PTF specified in the OATT.

Regional Network Load is the load that a Network Customer designates for Regional Network Service under Part II.B of the OATT. The Network Customer's Regional Network Load shall include all load designated by the Network Customer (including losses) and shall not be credited or reduced for any behind-the-meter generation. A Network Customer may elect to designate less than its total load as Regional Network Load but may not designate only part of the load at a discrete Point of Delivery. Where a Transmission Customer has elected not to designate a particular load at discrete Points of Delivery as Regional Network Load, the Transmission Customer is responsible for making separate arrangements

under Part II.C of the OATT for any Point-To-Point Service that may be necessary for such non-designated load.

Regional Network Service (RNS) is the transmission service over the PTF described in Part II.B of the OATT, including such service which is used with respect to Network Resources or Regional Network Load that is not physically interconnected with the PTF.

Regional Planning Dispute Resolution Process is described in Section 12 of Attachment K to the OATT.

Regional System Plan (RSP) is the plan developed under the process specified in Attachment K of the OATT.

Regional Transmission Service (RTS) is Regional Network Service and Through or Out Service as provided over the PTF in accordance with Section II.B, Section II.C, Schedule 8 and Schedule 9 of the OATT.

Regulation is the capability of a specific Resource with appropriate telecommunications, control and response capability to respond to an AGC SetPoint.

Regulation and Frequency Response Service is the form of Ancillary Service described in Schedule 3 of the OATT. The capability of performing Regulation and Frequency Response Service is referred to as automatic generation control (AGC).

Regulation Capacity is the lesser of five times the Automatic Response Rate and one-half of the difference between the Regulation High Limit and the Regulation Low Limit of a Resource capable of providing Regulation.

Regulation Capacity Requirement is the amount of Regulation Capacity required to maintain system control and reliability in the New England Control Area as calculated and posted on the ISO website.

Regulation Capacity Offer is an offer by a Market Participant to provide Regulation Capacity.

Regulation High Limit is an offer parameter that establishes the upper bound for AGC SetPoints and is used in the determination of a Resource's Regulation Capacity.

Regulation Low Limit is an offer parameter that establishes the lower bound for AGC SetPoints and is used in the determination of a Resource's Regulation Capacity.

Regulation Market is the market described in Section III.14 of Market Rule 1.

Regulation Resources are those Alternative Technology Regulation Resources and Generator Assets that satisfy the requirements of Section III.14.2. Regulation Resources are eligible to participate in the Regulation Market.

Regulation Service is the change in output or consumption made in response to changing AGC SetPoints.

Regulation Service Requirement is the estimated amount of Regulation Service required to maintain system control and reliability in the New England Control Area as calculated and posted on the ISO website.

Regulation Service Offer is an offer by a Market Participant to provide Regulation Service.

Related Person is defined pursuant to Section 1.1 of the Participants Agreement.

Related Transaction is defined in Section III.1.4.3 of Market Rule 1.

Reliability Administration Service (RAS) is the service provided by the ISO, as described in Schedule 3 of Section IV.A of the Tariff, in order to administer the Reliability Markets and provide other reliability-related and informational functions.

Reliability Committee is the committee whose responsibilities are specified in Section 8.2.3 of the Participants Agreement.

Reliability Markets are, collectively, the ISO's administration of Regulation, the Forward Capacity Market, and Operating Reserve.

Reliability Region means any one of the regions identified on the ISO's website. Reliability Regions are intended to reflect the operating characteristics of, and the major transmission constraints on, the New England Transmission System.

Reliability Transmission Upgrade means those additions and upgrades not required by the interconnection of a generator that are nonetheless necessary to ensure the continued reliability of the New England Transmission System, taking into account load growth and known resource changes, and include those upgrades necessary to provide acceptable stability response, short circuit capability and system voltage levels, and those facilities required to provide adequate thermal capability and local voltage levels that cannot otherwise be achieved with reasonable assumptions for certain amounts of generation being unavailable (due to maintenance or forced outages) for purposes of long-term planning studies. Good Utility Practice, applicable reliability principles, guidelines, criteria, rules, procedures and standards of ERO and NPCC and any of their successors, applicable publicly available local reliability criteria, and the ISO System Rules, as they may be amended from time to time, will be used to define the system facilities required to maintain reliability in evaluating proposed Reliability Transmission Upgrades. A Reliability Transmission Upgrade may provide market efficiency benefits as well as reliability benefits to the New England Transmission System.

Remittance Advice is an issuance from the ISO for the net Payment owed to a Covered Entity where a Covered Entity's total Payments exceed its total Charges in a billing period.

Remittance Advice Date is the day on which the ISO issues a Remittance Advice.

Renewable Technology Resource is a Generating Capacity Resource or an On-Peak Demand Resource that satisfies the requirements specified in Section III.13.1.1.1.7.

Re-Offer Period is the period that normally occurs between the posting of the of the Day-Ahead Energy Market results and 2:00 p.m. on the day before the Operating Day during which a Market Participant may submit revised Supply Offers, revised External Transactions, or revised Demand Bids associated with Dispatchable Asset Related Demands or, revised Demand Reduction Offers associated with Demand Response Resources.

Replacement Reserve is described in Part III, Section VII of ISO New England Operating Procedure No. 8.

Request for Alternative Proposals (RFAP) is the request described in Attachment K of the OATT.

Requested Billing Adjustment (RBA) is defined in Section 6.1 of the ISO New England Billing Policy.

Required Balance is an amount as defined in Section 5.3 of the Billing Policy.

Reseller is a MGTSA holder that sells, assigns or transfers its rights under its MGTSA, as described in Section II.45.1(a) of the OATT.

Reserve Adequacy Analysis is the analysis performed by the ISO to determine if adequate Resources are committed to meet forecasted load, Operating Reserve, and security constraint requirements for the current and next Operating Day.

Reserve Constraint Penalty Factors (RCPFs) are rates, in $/MWh, that are used within the Real-Time dispatch and pricing algorithm to reflect the value of Operating Reserve shortages and are defined in Section III.2.7A(c) of Market Rule 1; and, commencing on June 1, 2024, that are used within the Day-Ahead Energy Market security-constrained economic commitment and dispatch process to reflect the value of Day-Ahead Ancillary Services shortages and forecast energy requirement shortages and are defined in Section III.2.6.2(b) of Market Rule 1.

Reserve Quantity For Settlement is defined in Section III.10.1 of Market Rule 1.

Reserve Zone is defined in Section III.2.7 of Market Rule 1.

Reserved Capacity is the maximum amount of capacity and energy that is committed to the Transmission Customer for transmission over the New England Transmission System between the Point(s) of Receipt and the Point(s) of Delivery under Part II.C or Schedule 18, 20 or 21 of the OATT, as applicable. Reserved Capacity shall be expressed in terms of whole kilowatts on a sixty-minute interval (commencing on the clock hour) basis, or, in the case of Reserved Capacity for Local Point-to-Point Service, in terms of whole megawatts on a sixty-minute interval basis.

Resource means a Generator Asset, a Dispatchable Asset Related Demand, an External Resource, an External Transaction, or a Demand Response Resource.

Restated New England Power Pool Agreement (RNA) is the Second Restated New England Power Pool Agreement, which restated for a second time by an amendment dated as of August 16, 2004 the New England Power Pool Agreement dated September 1, 1971, as the same may be amended and restated from time to time, governing the relationship among the NEPOOL members.

Rest-of-Pool Capacity Zone is a single Capacity Zone made up of the adjacent Load Zones that are neither export-constrained nor import-constrained.

Rest of System is an area established under Section III.2.7(d) of Market Rule 1.

Retail Delivery Point is the point on the transmission or distribution system at which the load of an end-use facility, which is metered and assigned a unique account number by the Host Participant, is measured to determine the amount of energy delivered to the facility from the transmission and distribution system. If an end-use facility is connected to the transmission or distribution system at more than one location, the Retail Delivery Point shall consist of the metered load at each connection point, summed to measure the net energy delivered to the facility in each interval.

Retirement De-List Bid is a bid to retire an Existing Generating Capacity Resource, Existing Import Capacity Resource, or Existing Demand Capacity Resource from all New England Markets, as described in Section III.13.1.2.3.1.5.

Returning Market Participant is a Market Participant, other than an FTR-Only Customer or a Governance Only Member, whose previous membership as a Market Participant was involuntarily terminated due to a Financial Assurance Default or a payment default and, since returning, has been a Market Participant for less than six consecutive months.

Revenue Requirement is defined in Section IV.A.2.1 of the Tariff.

Reviewable Action is defined in Section III.D.1.1 of Appendix D of Market Rule 1.

Reviewable Determination is defined in Section 12.4(a) of Attachment K to the OATT.

RSP Project List is defined in Section 1 of Attachment K to the OATT.

RTEP02 Upgrade(s) means a Transmission Upgrade that was included in the annual NEPOOL Transmission Plan (also known as the "Regional Transmission Expansion Plan" or "RTEP") for the year 2002, as approved by ISO New England Inc.'s Board of Directors, or the functional equivalent of such Transmission Upgrade, as determined by ISO New England Inc. The RTEP02 Upgrades are listed in Schedule 12B of the OATT.

RTO is a regional transmission organization or comparable independent transmission organization that complies with Order No. 2000 and the Commission's corresponding regulation.

Same Reserve Zone Export Transaction is defined in Section III.1.10.7(f)(iii) of Market Rule 1.

Sanctionable Behavior is defined in Section III.B.3 of Appendix B of Market Rule 1.

Schedule, Schedules, Schedule 1, 2, 3, 4 and 5 are references to the individual or collective schedules to Section IV.A. of the Tariff.

Schedule 20A Service Provider (SSP) is defined in Schedule 20A to Section II of this Tariff.

Scheduling Service, for purposes of Section IV.A and Section IV.B of the Tariff, is the service described in Schedule 1 to Section IV.A of the Tariff.

Scheduling, System Control and Dispatch Service, for purposes of Section II of the Tariff, is the form of Ancillary Service described in Schedule 1 of the OATT.

Seasonal Claimed Capability is the summer or winter claimed capability of a Generator Asset or Generating Capacity Resource, and represents the maximum dependable load carrying ability of the asset or resource, excluding capacity required for station use.

Seasonal Claimed Capability Audit is the Generator Asset audit performed pursuant to Section III.1.5.1.3.

Seasonal DR Audit is the Demand Response Resource audit performed pursuant to Section III.1.5.1.3.1.

Seasonal Peak Demand Resource is a type of Demand Capacity Resource and shall mean installed measures (e.g., products, equipment, systems, services, practices and/or strategies) on end-use customer facilities that reduce the total amount of electrical energy consumed during Demand Resource Seasonal Peak Hours, while delivering a comparable or acceptable level of end-use service. Such measures include Energy Efficiency, Load Management, and Distributed Generation.

Section III.1.4 Transactions are defined in Section III.1.4.2 of Market Rule 1.

Section III.1.4 Conforming Transactions are defined in Section III.1.4.2 of Market Rule 1.

Security Agreement is Attachment 1 to the ISO New England Financial Assurance Policy.

Selected Qualified Transmission Project Sponsor is the Qualified Transmission Project Sponsor that proposed the Phase Two or Stage Two Solution that has been identified by the ISO as the preferred Phase Two or Stage Two Solution.

Selected Qualified Transmission Project Sponsor Agreement is the agreement between the ISO and a Selected Qualified Transmission Project Sponsor. The Selected Qualified Transmission Project Sponsor Agreement is provided in Attachment P to the OATT.

Self-Schedule is the action of a Market Participant in committing its Generator Asset or DARD, in accordance with applicable ISO New England Manuals, to provide service in an hour, whether or not in the absence of that action the Generator Asset or DARD would have been committed by the ISO to provide the service. For a Generator Asset, Self-Schedule is the action of a Market Participant in committing a Generator Asset to provide Energy in an hour at its Economic Minimum Limit, whether or not in the absence of that action the Generator Asset would have been committed by the ISO to provide the Energy. For a DARD, Self-Schedule is the action of a Market Participant in committing a DARD to consume Energy in an hour at its Minimum Consumption Limit, whether or not in the absence of that action the DARD would have been committed by the ISO to consume Energy. For an External Transaction, a Self-Schedule is a request by a Market Participant for the ISO to select the External Transaction regardless of the LMP. Demand Response Resources are not permitted to Self-Schedule.

Self-Supplied FCA Resource is described in Section III.13.1.6 of Market Rule 1.

Senior Officer means an officer of the subject entity with the title of vice president (or similar office) or higher, or another officer designated in writing to the ISO by that office.

Service Agreement is a Transmission Service Agreement or an MPSA.

Service Commencement Date is the date service is to begin pursuant to the terms of an executed Service Agreement, or the date service begins in accordance with the sections of the OATT addressing the filing of unexecuted Service Agreements.

Services means, collectively, the Scheduling Service, EAS and RAS; individually, a Service.

Settlement Financial Assurance is an amount of financial assurance required from a Designated FTR Participant awarded a bid in an FTR Auction. This amount is calculated pursuant to Section VI.C of the ISO New England Financial Assurance Policy.

Settlement Only Resources are generators of less than 5 MW or otherwise eligible for Settlement Only Resource treatment as described in ISO New England Operating Procedure No. 14 and that have elected Settlement Only Resource treatment as described in the ISO New England Manual for Registration and Performance Auditing.

Shortfall Funding Arrangement, as specified in Section 5.1 of the ISO New England Billing Policy, is a separate financing arrangement that can be used to make up any non-congestion related differences between amounts received on Invoices and amounts due for ISO Charges in any bill issued.

Short-Term is a period of less than one year.

Significantly Reduced Congestion Costs are defined in Section III.G.2.2 of Appendix G to Market Rule 1.

SMD Effective Date is March 1, 2003.

Solutions Study is described in Section 4.2(b) of Attachment K to the OATT.

Special Constraint Resource (SCR) is a Resource that provides Special Constraint Resource Service under Schedule 19 of the OATT.

Special Constraint Resource Service is the form of Ancillary Service described in Schedule 19 of the OATT.

Specified-Term Blackstart Capital Payment is the annual compensation level, as calculated pursuant to Section 5.1 of Schedule 16 of the OATT, for a Designated Blackstart Resource's capital Blackstart Equipment costs associated with the provision of Blackstart Service (except for capital costs associated with adhering to NERC Critical Infrastructure Protection Reliability Standards as part of Blackstart Service).

Sponsored Policy Resource is a New Capacity Resource that: receives an out-of-market revenue source supported by a government-regulated rate, charge or other regulated cost recovery mechanism, and; qualifies as a renewable, clean or alternative energy resource under a renewable energy portfolio standard, clean energy standard, alternative energy portfolio standard, renewable energy goal, or clean energy goal enacted (either by statute or regulation) in the New England state from which the resource receives the out-of-market revenue source and that is in effect on January 1, 2018.

Stage One Proposal is a first round submission, as defined in Sections 4A.5 of Attachment K of the OATT, of a proposal for a Public Policy Transmission Upgrade by a Qualified Transmission Project Sponsor.

Stage Two Solution is a second round submission, as defined in Section 4A.5 of Attachment K of the OATT, of a proposal for a Public Policy Transmission Upgrade by a Qualified Transmission Project Sponsor.

Standard Blackstart Capital Payment is the annual compensation level, as calculated pursuant to Section 5.1 of Schedule 16 of the OATT, for a Designated Blackstart Resource's capital Blackstart Equipment costs associated with the provision of Blackstart Service (except for capital costs associated with adhering to NERC Critical Infrastructure Protection Reliability Standards as part of Blackstart Service).

Start-of-Round Price is the highest price associated with a round of a Forward Capacity Auction as described in Section III.13.2.3.1 of Market Rule 1.

Start-Up Fee is the amount, in dollars, that must be paid for a Generator Asset to Market Participants with an Ownership Share in the Generator Asset each time the Generator Asset is scheduled in the New England Markets to start-up.

Start-Up Time is the time it takes the Generator Asset, after synchronizing to the system, to reach its Economic Minimum Limit and, for dispatchable Generator Assets, be ready for further dispatch by the ISO.

State Estimator means the computer model of power flows specified in Section III.2.3 of Market Rule 1.

Statements, for the purpose of the ISO New England Billing Policy, refer to both Invoices and Remittance Advices.

Static De-List Bid is a bid that may be submitted by an Existing Generating Capacity Resource, Existing Import Capacity Resource, or Existing Demand Capacity Resource in the Forward Capacity Auction to remove itself from the capacity market for a one year period, as described in Section III.13.1.2.3.1.1 of Market Rule 1.

Station is one or more Existing Generating Capacity Resources consisting of one or more assets located within a common property boundary.

Station Going Forward Common Costs are the net costs associated with a Station that are avoided only by the clearing of the Static De-List Bids, the Permanent De-List Bids or the Retirement De-List Bids of all the Existing Generating Capacity Resources comprising the Station.

Station-level Blackstart O&M Payment is defined and calculated as specified in Section 5.1.2 of Schedule 16 to the OATT.

Station-level Specified-Term Blackstart Capital Payment is defined and calculated as specified in Section 5.1.2 of Schedule 16 to the OATT.

Station-level Standard Blackstart Capital Payment is defined and calculated as specified in Section 5.1.2 of Schedule 16 to the OATT.

Storage DARD is a DARD that participates in the New England Markets as part of an Electric Storage Facility, as described in Section III.1.10.6 of Market Rule 1.

Summer ARA Qualified Capacity is described in Section III.13.4.2.1.2.1.1.1 of Market Rule 1.

Summer Capability Period means one of two time periods defined by the ISO for the purposes of rating and auditing resources pursuant to Section III.9. The time period associated with the Summer Capability Period is the period of June 1 through September 30.

Summer Intermittent Reliability Hours are defined in Section III.13.1.2.2.2.1(c) of Market Rule 1.

Supply Offer is a proposal to furnish energy at a Node or Regulation from a Resource that meets the applicable requirements set forth in the ISO New England Manuals submitted to the ISO by a Market Participant with authority to submit a Supply Offer for the Resource. The Supply Offer will be submitted pursuant to Market Rule 1 and applicable ISO New England Manuals, and include a price and information with respect to the quantity proposed to be furnished, technical parameters for the Resource, timing and other matters. A Supply Offer is a subset of the information required in a Market Participant's Offer Data.

Supply Offer Block-Hours are Block-Hours assigned to the Lead Market Participant for each Supply Offer. Blocks of the Supply Offer in effect for each hour will be totaled to determine the quantity of Supply Offer Block-Hours for a given day. In the case that a Resource has a Real-Time unit status of "unavailable" for the entire day, that day will not contribute to the quantity of Supply Offer Block-Hours. However, if the Resource has at least one hour of the day with a unit status of "available," the entire day will contribute to the quantity of Supply Offer Block-Hours.

Synchronous Condenser is a generator that is synchronized to the grid but supplying no energy for the purpose of providing Operating Reserve or VAR or voltage support.

System Condition is a specified condition on the New England Transmission System or on a neighboring system, such as a constrained transmission element or flowgate, that may trigger Curtailment of Long-

Term Firm MTF or OTF Service on the MTF or the OTF using the curtailment priority pursuant to Section II.44 of the Tariff or Curtailment of Local Long-Term Firm Point-to-Point Transmission Service on the non-PTF using the curtailment priority pursuant to Schedule 21 of the Tariff. Such conditions must be identified in the Transmission Customer's Service Agreement.

System Impact Study is an assessment pursuant to Part II.B, II.C, II.G, Schedule 21, Schedule 22, Schedule 23, or Schedule 25 of the OATT of (i) the adequacy of the PTF or Non-PTF to accommodate a request for the interconnection of a new or materially changed generating unit or a new or materially changed interconnection to another Control Area or new Regional Network Service or new Local Service or an Elective Transmission Upgrade, and (ii) whether any additional costs may be required to be incurred in order to provide the interconnection or transmission service.

System Operator shall mean ISO New England Inc. or a successor organization.

System Operating Limit (SOL) has the meaning specified in the Glossary of Terms Used in NERC Reliability Standards.

System-Wide Capacity Demand Curve is the demand curve used in the Forward Capacity Market as specified in Section III.13.2.2.

TADO is the total amount due and owing (not including any amounts due under Section 14.1 of the RNA) at such time to the ISO, NEPOOL, the PTOs, the Market Participants and the Non-Market Participant Transmission Customers, by all PTOs, Market Participants and Non-Market Participant Transmission Customers.

Tangible Net Worth is the value, determined in accordance with international accounting standards or generally accepted accounting principles in the United States, of all of that entity's assets less the following: (i) assets the ISO reasonably believes to be restricted or potentially unavailable to settle a claim in the event of a default (e.g., regulatory assets, restricted assets, and Affiliate assets), net of any matching liabilities, to the extent that the result of that netting is a positive value; (ii) derivative assets, net of any matching liabilities, to the extent that the result of that netting is a positive value; (iii) the amount at which the liabilities of the entity would be shown on a balance sheet in accordance with international accounting standards or generally accepted accounting principles in the United States; (iv) preferred stock: (v) non-controlling interest; and (vi) all of that entity's intangible assets (e.g., patents, trademarks,

franchises, intellectual property, goodwill and any other assets not having a physical existence), in each case as shown on the most recent financial statements provided by such entity to the ISO.

Technical Committee is defined in Section 8.2 of the Participants Agreement.

Ten-Minute Non-Spinning Reserve (TMNSR) is a form of ten-minute reserve capability, determined pursuant to Section III.1.7.19.2.

Ten-Minute Non-Spinning Reserve Service is the form of Ancillary Service described in Schedule 6 of the OATT.

Ten-Minute Reserve Requirement is the combined amount of TMSR and TMNSR required system-wide as described in Section III.2.7A and ISO New England Operating Procedure No. 8.

Ten-Minute Spinning Reserve (TMSR) is a form of ten-minute reserve capability, determined pursuant to Section III.1.7.19.2.

Ten-Minute Spinning Reserve Requirement is the amount of TMSR required system-wide as described in Section III.2.7A and ISO New England Operating Procedure No. 8.

Ten-Minute Spinning Reserve Service is the form of Ancillary Service described in Schedule 5 of the OATT.

Third-Party Sale is any sale for resale in interstate commerce to a Power Purchaser that is not designated as part of Regional Network Load or Local Network Load under the Regional Network Service or Local Network Service, as applicable.

Thirty-Minute Operating Reserve (TMOR) is a form of thirty-minute reserve capability, determined pursuant to Section III.1.7.19.2.

Thirty-Minute Operating Reserve Service is the form of Ancillary Service described in Schedule 7 of the OATT.

Through or Out Rate (TOUT Rate) is the rate per hour for Through or Out Service, as defined in Section II.25.2 of the OATT.

Through or Out Service (TOUT Service) means Point-To-Point Service over the PTF provided by the ISO with respect to a transaction that goes through the New England Control Area, as, for example, a single transaction where energy or capacity is transmitted into the New England Control Area from New Brunswick and subsequently out of the New England Control Area to New York, or a single transaction where energy or capacity is transmitted into the New England Control Area from New York through one point on the PTF and subsequently flows over the PTF prior to passing out of the New England Control Area to New York, or with respect to a transaction which originates at a point on the PTF and flows over the PTF prior to passing out of the New England Control Area, as, for example, from Boston to New York.

Tie-Line Asset is a physical transmission tie-line, or an inter-state or intra-state border arrangement created according to the ISO New England Manuals and registered in accordance with the Asset Registration Process.

Total Available Amount is the sum of the available amount of the Shortfall Funding Arrangement and the balance in the Payment Default Shortfall Fund.

Total Blackstart Capital Payment is the annual compensation calculated under either Section 5.1 or Section 5.2 of Schedule 16 of the OATT, as applicable.

Total Blackstart Service Payments is monthly compensation to Blackstart Owners or Market Participants, as applicable, and as calculated pursuant to Section 5.6 of Schedule 16 to the OATT.

Total Reserve Requirement, which includes Replacement Reserve, is the combined amount of TMSR, TMNSR, and TMOR required system-wide as described in Section III.2.7A and ISO New England Operating Procedure No. 8.

Total System Capacity is the aggregate capacity supply curve for the New England Control Area as determined in accordance with Section III.13.2.3.3 of Market Rule 1.

Transaction Unit (TU) is a type of billing determinant under Schedule 2 of Section IV.A of the Tariff used to assess charges to Customers.

Transition Period: The six-year period commencing on March 1, 1997.

Transmission Charges, for the purposes of the ISO New England Financial Assurance Policy and the ISO New England Billing Policy, are all charges and payments under Schedules 1, 8 and 9 of the OATT.

Transmission Congestion Credit means the allocated share of total Transmission Congestion Revenue credited to each holder of Financial Transmission Rights, calculated and allocated as specified in Section III.5.2 of Market Rule 1.

Transmission Congestion Revenue is defined in Section III.5.2.5(a) of Market Rule 1.

Transmission Constraint Penalty Factors are described in Section III.1.7.5 of Market Rule 1.

Transmission Credit Limit is a credit limit, not to be used to meet FTR Requirements, established for each Market Participant in accordance with Section II.D and each Non-Market Participant Transmission Customer in accordance with Section V.B.2 of the ISO New England Financial Assurance Policy.

Transmission Credit Test Percentage is calculated in accordance with Section III.B.1(c) of the ISO New England Financial Assurance Policy.

Transmission Customer is any Eligible Customer that (i) executes, on its own behalf or through its Designated Agent, an MPSA or TSA, or (ii) requests in writing, on its own behalf or through its Designated Agent, that the ISO, the Transmission Owner, or the Schedule 20A Service Provider, as applicable, file with the Commission, a proposed unexecuted MPSA or TSA containing terms and conditions deemed appropriate by the ISO (in consultation with the applicable PTO, OTO or Schedule 20A Service Provider) in order that the Eligible Customer may receive transmission service under Section II of this Tariff. A Transmission Customer under Section II of this Tariff includes a Market Participant or a Non-Market Participant taking Regional Network Service, Through or Out Service, MTF Service, OTF Service, Ancillary Services, or Local Service.

Transmission Default Amount is all or any part of any amount of Transmission Charges due to be paid by any Covered Entity that the ISO, in its reasonable opinion, believes will not or has not been paid when due.

Transmission Default Period is defined in Section 3.4.f of the ISO New England Billing Policy.

Transmission Late Payment Account is defined in Section 4.2 of the ISO New England Billing Policy.

Transmission Late Payment Account Limit is defined in Section 4.2 of the ISO New England Billing Policy.

Transmission Late Payment Charge is defined in Section 4.1 of the ISO New England Billing Policy.

Transmission, Markets and Services Tariff (Tariff) is the ISO New England Inc. Transmission, Markets and Services Tariff, as amended from time to time.

Transmission Obligations are determined in accordance with Section III.A(vi) of the ISO New England Financial Assurance Policy.

Transmission Operating Agreement (TOA) is the Transmission Operating Agreement between and among the ISO and the PTOs, as amended and restated from time to time.

Transmission Owner means a PTO, MTO or OTO.

Transmission Provider is the ISO for Regional Network Service and Through or Out Service as provided under Section II.B and II.C of the OATT; Cross-Sound Cable, LLC for Merchant Transmission Service as provided under Schedule 18 of the OATT; the Schedule 20A Service Providers for Phase I/II HVDC-TF Service as provided under Schedule 20A of the OATT; and the Participating Transmission Owners for Local Service as provided under Schedule 21 of the OATT.

Transmission Requirements are determined in accordance with Section III.A(iii) of the ISO New England Financial Assurance Policy.

Transmission Security Analysis Requirement shall be determined pursuant to Section III.12.2.1.2.

Transmission Service Agreement (TSA) is the initial agreement and any amendments or supplements thereto: (A) in the form specified in either Attachment A or B to the OATT, entered into by the Transmission Customer and the ISO for Regional Network Service or Through or Out Service; (B) entered into by the Transmission Customer with the ISO and PTO in the form specified in Attachment A to Schedule 21 of the OATT; (C) entered into by the Transmission Customer with an OTO or Schedule 20A Service Provider in the appropriate form specified under Schedule 20 of the OATT; or (D) entered into by the Transmission Customer with a MTO in the appropriate form specified under Schedule 18 of the OATT. A Transmission Service Agreement shall be required for Local Service, MTF Service and OTF Service, and shall be required for Regional Network Service and Through or Out Service if the Transmission Customer has not executed a MPSA.

Transmission Upgrade(s) means an upgrade, modification or addition to the PTF that becomes subject to the terms and conditions of the OATT governing rates and service on the PTF on or after January 1, 2004. This categorization and cost allocation of Transmission Upgrades shall be as provided for in Schedule 12 of the OATT.

UDS is unit dispatch system software.

Unconstrained Export Transaction is defined in Section III.1.10.7(f)(iv) of Market Rule 1.

Uncovered Default Amount is defined in Section 3.3(i) of the ISO New England Billing Policy.

Uncovered Transmission Default Amounts are defined in Section 3.4.f of the ISO New England Billing Policy.

Unrated means a Market Participant that is not a Rated Market Participant.

Unsecured Covered Entity is, collectively, an Unsecured Municipal Market Participant and an Unsecured Non-Municipal Covered Entity.

Unsecured Municipal Default Amount is defined in Section 3.3(i) of the ISO New England Billing Policy.

Unsecured Municipal Market Participant is defined in Section 3.3(h) of the ISO New England Billing Policy.

Unsecured Municipal Transmission Default Amount is defined in Section 3.4.f of the ISO New England Billing Policy.

Unsecured Non-Municipal Covered Entity is a Covered Entity that is not a Municipal Market Participant or a Non-Market Participant Transmission Customer and has a Market Credit Limit or Transmission Credit Limit of greater than $0 under the ISO New England Financial Assurance Policy.

Unsecured Non-Municipal Default Amount is defined in Section 3.3(i) of the ISO New England Billing Policy.

Unsecured Non-Municipal Transmission Default Amount is defined in Section 3.3(i) of the ISO New England Billing Policy.

Unsecured Transmission Default Amounts are, collectively, the Unsecured Municipal Transmission Default Amount and the Unsecured Non-Municipal Transmission Default Amount.

Unsettled FTR Financial Assurance is an amount of financial assurance required from a Designated FTR Participant as calculated pursuant to Section VI.B of the ISO New England Financial Assurance Policy.

Updated Measurement and Verification Plan is an optional Measurement and Verification Plan that may be submitted as part of a subsequent qualification process for a Forward Capacity Auction prior to the beginning of the Capacity Commitment Period of the On-Peak Demand Resource or Seasonal Peak Demand Response project. The Updated Measurement and Verification Plan may include updated project specifications, measurement and verification protocols, and performance data as described in Section III.13.1.4.3.1.2 of Market Rule 1 and the ISO New England Manuals.

VAR CC Rate is the CC rate paid to Qualified Reactive Resources for VAR Service capability under Section IV.A of Schedule 2 of the OATT.

VAR Payment is the payment made to Qualified Reactive Resources for VAR Service capability under Section IV.A of Schedule 2 of the OATT.

VAR Service is the provision of reactive power voltage support to the New England Transmission System by a Qualified Reactive Resource or by other generators that are dispatched by the ISO to provide dynamic reactive power as described in Schedule 2 of the OATT.

Virtual Cap is $2,000/MWh.

Virtual Requirements are determined in accordance with Section III.A(iv) of the ISO New England Financial Assurance Policy.

Volt Ampere Reactive (VAR) is a measurement of reactive power.

Volumetric Measure (VM) is a type of billing determinant under Schedule 2 of Section IV.A of the Tariff used to assess charges to Customers under Section IV.A of the Tariff.

Winter ARA Qualified Capacity is described in Section III.13.4.2.1.2.1.1.2 of Market Rule 1.

Winter Capability Period means one of two time periods defined by the ISO for the purposes of rating and auditing resources pursuant to Section III.9. The time period associated with the Winter Capability Period is the period October 1 through May 31.

Winter Intermittent Reliability Hours are defined in Section III.13.1.2.2.2.2(c) of Market Rule 1.

Year means a period of 365 or 366 days, whichever is appropriate, commencing on, or on the anniversary of March 1, 1997. Year One is the Year commencing on March 1, 1997, and Years Two and higher follow it in sequence.

Zonal Price is calculated in accordance with Section III.2.7 of Market Rule 1.

Zonal Capacity Obligation is calculated in accordance with Section III.13.7.5.2 of Market Rule 1.

Zonal Reserve Requirement is the combined amount of TMSR, TMNSR, and TMOR required for a Reserve Zone as described in Section III.2.7A and ISO New England Operating Procedure No. 8.

STANDARD MARKET DESIGN

III.1 Market Operations

III.1.1 Introduction.

This Market Rule 1 sets forth the scheduling, other procedures, and certain general provisions applicable to the operation of the New England Markets within the New England Control Area. The ISO shall operate the New England Markets in compliance with NERC, NPCC and ISO reliability criteria. The ISO is the Counterparty for agreements and transactions with its Customers (including assignments involving Customers), including bilateral transactions described in Market Rule 1, and sales to the ISO and/or purchases from the ISO of energy, reserves, Ancillary Services, capacity, demand/load response, FTRs and other products, paying or charging (if and as applicable) its Customers the amounts produced by the pertinent market clearing process or through the other pricing mechanisms described in Market Rule 1. The bilateral transactions to which the ISO is the Counterparty (subject to compliance with the requirements of Section III.1.4) include, but are not limited to, Internal Bilaterals for Load, Internal Bilaterals for Market for Energy, Annual Reconfiguration Transactions, Capacity Supply Obligation Bilaterals, Capacity Load Obligation Bilaterals, Capacity Performance Bilaterals, and the transactions described in Sections III.9.4.1 (internal bilateral transactions that transfer Forward Reserve Obligations), and III.13.1.6 (Self-Supplied FCA Resources). Notwithstanding the foregoing, the ISO will not act as Counterparty for the import into the New England Control Area, for the use of Publicly Owned Entities, of: (1) energy, capacity, and ancillary products associated therewith, to which the Publicly Owned Entities are given preference under Articles 407 and 408 of the project license for the New York Power Authority's Niagara Project; and (2) energy, capacity, and ancillary products associated therewith, to which Publicly Owned Entities are entitled under Article 419 of the project license for the New York Power Authority's Franklin D. Roosevelt – St. Lawrence Project. This Market Rule 1 addresses each of the three time frames pertinent to the daily operation of the New England Markets: "Pre-scheduling" as specified in Section III.1.9, "Scheduling" as specified in III.1.10, and "Dispatch" as specified in III.1.11. This Market Rule 1 became effective on February 1, 2005.

III.1.2 [Reserved.]

III.1.3 Definitions.

Whenever used in Market Rule 1, in either the singular or plural number, capitalized terms shall have the meanings specified in Section I of the Tariff. Terms used in Market Rule 1 that are not defined in Section

I shall have the meanings customarily attributed to such terms by the electric utility industry in New England or as defined elsewhere in the ISO New England Filed Documents. Terms used in Market Rule 1 that are defined in Section I are subject to the 60% Participant Vote threshold specified in Section 11.1.2 of the Participants Agreement.

III.1.3.1 [Reserved.]

III.1.3.2 [Reserved.]

III.1.3.3 [Reserved.]

III.1.4 Requirements for Certain Transactions.

III.1.4.1 ISO Settlement of Certain Transactions.

The ISO will settle, and act as Counterparty to, the transactions described in Section III.1.4.2 if the transactions (and their related transactions) conform to, and the transacting Market Participants comply with, the requirements specified in Section III.1.4.3.

III.1.4.2 Transactions Subject to Requirements of Section III.1.4.

Transactions that must conform to the requirements of Section III.1.4 include: Internal Bilaterals for Load, Internal Bilaterals for Market for Energy, Annual Reconfiguration Transactions, Capacity Supply Obligation Bilaterals, Capacity Load Obligation Bilaterals, Capacity Performance Bilaterals, and the transactions described in Sections III.9.4.1 (internal bilateral transactions that transfer Forward Reserve Obligations), and III.13.1.6 (Self-Supplied FCA Resources). The foregoing are referred to collectively as "Section III.1.4 Transactions," and individually as a "Section III.1.4 Transaction." Transactions that conform to the standards are referred to collectively as "Section III.1.4 Conforming Transactions," and individually as a "Section III.1.4 Conforming Transaction."

III.1.4.3 Requirements for Section III.1.4 Conforming Transactions.

(a) To qualify as a Section III.1.4 Conforming Transaction, a Section III.1.4 Transaction must constitute an exchange for an off-market transaction (a "Related Transaction"), where the Related Transaction:

(i) is not cleared or settled by the ISO as Counterparty;

(ii) is a spot, forward or derivatives contract that contemplates the transfer of energy or a MW obligation to or from a Market Participant;

(iii) involves commercially appropriate obligations that impose a duty to transfer electricity or a MW obligation from the seller to the buyer, or from the buyer to the seller, with performance taking place within a reasonable time in accordance with prevailing cash market practices; and

(iv) is not contingent on either party to carry out the Section III.1.4 Transaction.

(b) In addition, to qualify as a Section III.1.4 Conforming Transaction:

(i) the Section III.1.4 Transaction must be executed between separate beneficial owners or separate parties trading for independently controlled accounts;

(ii) the Section III.1.4 Transaction and the Related Transaction must be separately identified in the records of the parties to the transactions; and

(iii) the Section III.1.4 Transaction must be separately identified in the records of the ISO.

(c) As further requirements:

(i) each party to the Section III.1.4 Transaction and Related Transaction must maintain, and produce upon request of the ISO, records demonstrating compliance with the requirements of Sections III.1.4.3(a) and (b) for the Section III.1.4 Transaction, the Related Transaction and any other transaction that is directly related to, or integrated in any way with, the Related Transaction, including the identity of the counterparties and the material economic terms of the transactions including their price, tenor, quantity and execution date; and

(ii) each party to the Section III.1.4 Transaction must be a Market Participant that meets all requirements of the ISO New England Financial Assurance Policy.

III.1.5 Resource Auditing.

III.1.5.1 Claimed Capability Audits.

III.1.5.1.1 General Audit Requirements.

(a) The following types of Claimed Capability Audits may be performed:

(i) An Establish Claimed Capability Audit establishes the Generator Asset's ability to respond to ISO Dispatch Instructions and to maintain performance at a specified output level for a specified duration.

(ii) A Seasonal Claimed Capability Audit determines a Generator Asset's capability to perform under specified summer and winter conditions for a specified duration.

(iii) A Seasonal DR Audit determines the ability of a Demand Response Resource to perform during specified months for a specified duration.

(iv) An ISO-Initiated Claimed Capability Audit is conducted by the ISO to verify the Generator Asset's Establish Claimed Capability Audit value or the Demand Response Resource's Seasonal DR Audit value.

(b) The Claimed Capability Audit value of a Generator Asset shall reflect any limitations based upon the interdependence of common elements between two or more Generator Assets such as: auxiliaries, limiting operating parameters, and the deployment of operating personnel.

(c) The Claimed Capability Audit value of gas turbine, combined cycle, and pseudo-combined cycle assets shall be normalized to standard 90° (summer) and 20° (winter) temperatures.

(d) The Claimed Capability Audit value for steam turbine assets with steam exports, combined cycle, or pseudo-combined cycle assets with steam exports where steam is exported for uses external to the electric power facility, shall be normalized to the facility's Seasonal Claimed Capability steam demand.

(e) A Claimed Capability Audit may be denied or rescheduled by the ISO if its performance will jeopardize the reliable operation of the electrical system.

III.1.5.1.2 Establish Claimed Capability Audit.

(a) An Establish Claimed Capability Audit may be performed only by a Generator Asset.

(b) The time and date of an Establish Claimed Capability Audit shall be unannounced.

(c) For a newly commercial Generator Asset:

(i) An Establish Claimed Capability Audit will be scheduled by the ISO within five Business Days of the commercial operation date for all Generator Assets except:

1. Non-intermittent daily cycle hydro;
2. Non-intermittent net-metered, or special qualifying facilities that do not elect to audit as described in Section III.1.5.1.3; and
3. Intermittent Generator Assets

(ii) The Establish Claimed Capability Audit values for both summer and winter shall equal the mean net real power output demonstrated over the duration of the audit, as reflected in hourly revenue metering data, normalized for temperature and steam exports.

(iii) The Establish Claimed Capability Audit values shall be effective as of the commercial operation date of the Generator Asset.

(d) For Generator Assets with an Establish Claimed Capability Audit value:

(i) An Establish Claimed Capability Audit may be performed at the request of a Market Participant in order to support a change in the summer and winter Establish Claimed Capability Audit values for a Generator Asset.

(ii) An Establish Claimed Capability Audit shall be performed within five Business Days of the date of the request.

(iii) The Establish Claimed Capability Audit values for both summer and winter shall equal the mean net real power output demonstrated over the duration of the audit, as reflected in hourly revenue metering data, normalized for temperature and steam exports.

(iv) The Establish Claimed Capability Audit values become effective one Business Day following notification of the audit results to the Market Participant by the ISO.

(v) A Market Participant may cancel an audit request prior to issuance of the audit Dispatch Instruction.

(e) An Establish Claimed Capability Audit value may not exceed the maximum interconnected flow specified in the Network Resource Capability for the resource associated with the Generator Asset.

(f) Establish Claimed Capability Audits shall be performed on non-NERC holiday weekdays between 0800 and 2200.

(g) To conduct an Establish Claimed Capability Audit, the ISO shall:

(i) Initiate an Establish Claimed Capability Audit by issuing a Dispatch Instruction ordering the Generator Asset's net output to increase from the current operating level to its Real-Time High Operating Limit.

(ii) Indicate when issuing the Dispatch Instruction that an audit will be conducted.

(iii) Begin the audit with the first full clock hour after sufficient time has been allowed for the asset to ramp, based on its offered ramp rate from its current operating point to reach its Real-Time High Operating Limit.

(h) An Establish Claimed Capability Audit shall be performed for the following contiguous duration:

Duration Required for an Establish Claimed Capability Audit	
Type	**Claimed Capability Audit Duration (Hrs)**
Steam Turbine (Includes Nuclear)	4
Combined Cycle	4
Integrated Coal Gasification Combustion Cycle	4
Pressurized Fluidized Bed Combustion	4

Combustion Gas Turbine	1
Internal Combustion Engine	1
Hydraulic Turbine – Reversible (Electric Storage) Hydraulic Turbine – Other	2
Hydro-Conventional Daily Pondage Hydro-Conventional Run of River Hydro-Conventional Weekly	2
Wind Photovoltaic Fuel Cell	2
Other Electric Storage (Excludes Hydraulic Turbine - Reversible)	2

(i) The ISO, in consultation with the Market Participant, will determine the contiguous audit duration for a Generator Asset of a type not listed in Section III.1.5.1.2(h).

III.1.5.1.3. Seasonal Claimed Capability Audits.

(a) A Seasonal Claimed Capability Audit may be performed only by a Generator Asset.

(b) A Seasonal Claimed Capability Audit must be conducted by all Generator Assets except:

(i) Non-intermittent daily hydro; and

(ii) Intermittent, net-metered, and special qualifying facilities. Non-intermittent net-metered and special qualifying facilities may elect to perform Seasonal Claimed Capability Audits pursuant to Section III.1.7.11(c)(iv).

(c) An Establish Claimed Capability Audit or ISO-Initiated Claimed Capability Audit that meets the requirements of a Seasonal Claimed Capability Audit in this Section III.1.5.1.3 may be used to fulfill a Generator Asset's Seasonal Claimed Capability Audit obligation.

(d) Except as provided in Section III.1.5.1.3(n) below, a summer Seasonal Claimed Capability Audit must be conducted:

(i) At least once every Capability Demonstration Year;

(ii) Either (1) at a mean ambient temperature during the audit that is greater than or equal to 80 degrees Fahrenheit at the location of the Generator Asset, or (2) during an ISO-announced summer Seasonal Claimed Capability Audit window.

(e) A winter Seasonal Claimed Capability Audit must be conducted:

(i) At least once in the previous three Capability Demonstration Years, except that a newly commercial Generator Asset which becomes commercial on or after:

(1) September 1 and prior to December 31 shall perform a winter Seasonal Claimed Capability Audit prior to the end of that Capability Demonstration Year.

(2) January 1 shall perform a winter Seasonal Claimed Capability Audit prior to the end of the next Capability Demonstration Year.

(ii) Either (1) at a mean ambient temperature during the audit that is less than or equal to 32 degrees Fahrenheit at the location of the Generator Asset, or (2) during an ISO-announced winter Seasonal Claimed Capability Audit window.

(f) A Seasonal Claimed Capability Audit shall be performed by operating the Generator Asset for the audit time period and submitting to the ISO operational data that meets the following requirements:

(i) The Market Participant must notify the ISO of its request to use the dispatch to satisfy the Seasonal Claimed Capability Audit requirement by 5:00 p.m. on the fifth Business Day following the day on which the audit concludes.

(ii) The notification must include the date and time period of the demonstration to be used for the Seasonal Claimed Capability Audit and other relevant operating data.

(g) The Seasonal Claimed Capability Audit value (summer or winter) will be the mean net real power output demonstrated over the duration of the audit, as reflected in hourly revenue metering data, normalized for temperature and steam exports.

(h) The Seasonal Claimed Capability Audit value (summer or winter) shall be the most recent audit data submitted to the ISO meeting the requirements of this Section III.1.5.1.3. In the event that a Market Participant fails to submit Seasonal Claimed Capability Audit data to meet the timing requirements in Section III.1.5.1.3(d) and (e), the Seasonal Claimed Capability Audit value for the season shall be set to zero.

(i) The Seasonal Claimed Capability Audit value shall become effective one Business Day following notification of the audit results to the Market Participant by the ISO.

(j) A Seasonal Claimed Capability Audit shall be performed for the following contiguous duration:

Duration Required for a Seasonal Claimed Capability Audit	
Type	**Claimed Capability Audit Duration (Hrs)**
Steam Turbine (Includes Nuclear)	2
Combined Cycle	2

Integrated Coal Gasification Combustion Cycle	2
Pressurized Fluidized Bed Combustion	2
Combustion Gas Turbine	1
Internal Combustion Engine	1
Hydraulic Turbine-Reversible (Electric Storage) Hydraulic Turbine-Other	2
Hydro-Conventional Weekly	2
Fuel Cell	1
Other Electric Storage (Excludes Hydraulic Turbine - Reversible)	2

(k) A Generator Asset that is on a planned outage that was approved in the ISO's annual maintenance scheduling process during all hours that meet the temperature requirements for a Seasonal Claimed Capability Audit that is to be performed by the asset during that Capability Demonstration Year shall:

(i) Submit to the ISO, prior to September 10, an explanation of the circumstances rendering it incapable of meeting these auditing requirements;

(ii) Have its Seasonal Claimed Capability Audit value for the season set to zero; and

(iii) Perform the required Seasonal Claimed Capability Audit on the next available day that meets the Seasonal Claimed Capability Audit temperature requirements.

(l) A Generator Asset that does not meet the auditing requirements of this Section III.1.5.1.3 because (1) every time the temperature requirements were met at the Generator Asset's location the ISO denied the request to operate to full capability, or (2) the temperature requirements were not met at the Generator Asset's location during the Capability Demonstration Year during which the asset was required to perform a Seasonal Claimed Capability Audit during the hours 0700 to 2300 for each weekday excluding those weekdays that are defined as NERC holidays, shall:

(i) Submit to the ISO, prior to September 10, an explanation of the circumstances rendering it incapable of meeting these temperature requirements, including verifiable temperature data;

(ii) Retain the current Seasonal Claimed Capability Audit value for the season; and

(iii) Perform the required Seasonal Claimed Capability Audit during the next Capability Demonstration Year.

(m) The ISO may issue notice of a summer or winter Seasonal Claimed Capability Audit window for some or all of the New England Control Area if the ISO determines that weather forecasts indicate that temperatures during the audit window will meet the summer or winter Seasonal

Claimed Capability Audit temperature requirements. A notice shall be issued at least 48 hours prior to the opening of the audit window. Any audit performed during the announced audit window shall be deemed to meet the temperature requirement for the summer or winter audit. In the event that five or more audit windows for the summer Seasonal Claimed Capability Audit temperature requirement, each of at least a four hour duration between 0700 and 2300 and occurring on a weekday excluding those weekdays that are defined as NERC holidays, are not opened for a Generator Asset prior to August 15 during a Capability Demonstration Year, a two-week audit window shall be opened for that Generator Asset to perform a summer Seasonal Claimed Capability Audit, and any audit performed by that Generator Asset during the open audit window shall be deemed to meet the temperature requirement for the summer Seasonal Claimed Capability Audit. The open audit window shall be between 0700 and 2300 each day during August 15 through August 31.

(n) A Market Participant that is required to perform testing on a Generator Asset that is in addition to a summer Seasonal Claimed Capability Audit may notify the ISO that the summer Seasonal Claimed Capability Audit was performed in conjunction with this additional testing, provided that:

(i) The notification shall be provided at the time the Seasonal Claimed Capability Audit data is submitted under Section III.1.5.1.3(f).

(ii) The notification explains the nature of the additional testing and that the summer Seasonal Claimed Capability Audit was performed while the Generator Asset was online to perform this additional testing.

(iii) The summer Seasonal Claimed Capability Audit and additional testing are performed during the months of June, July or August between the hours of 0700 and 2300.

(iv) In the event that the summer Seasonal Claimed Capability Audit does not meet the temperature requirements of Section III.1.5.1.3(d)(ii), the summer Seasonal Claimed Capability Audit value may not exceed the summer Seasonal Claimed Capability Audit value from the prior Capability Demonstration Year.

(v) This Section III.1.5.1.3(n) may be utilized no more frequently than once every three Capability Demonstration Years for a Generator Asset.

(o) The ISO, in consultation with the Market Participant, will determine the contiguous audit duration for a Generator Asset of a type not listed in Section III.1.5.1.3(j).

III.1.5.1.3.1 Seasonal DR Audits.

(a) A Seasonal DR Audit may be performed only by a Demand Response Resource.

(b) A Seasonal DR Audit shall be performed for 12 contiguous five-minute intervals.

(c) A summer Seasonal DR Audit must be conducted by all Demand Response Resources:

(i) At least once every Capability Demonstration Year;

(ii) During the months of April through November;

(d) A winter Seasonal DR Audit must be conducted by all Demand Response Resources:

(i) At least once every Capability Demonstration Year;

(ii) During the months of December through March.

(e) A Seasonal DR Audit may be performed either:

(i) At the request of a Market Participant as described in subsection (f) below; or

(ii) By the Market Participant designating a period of dispatch after the fact as described in subsection (g) below.

(f) If a Market Participant requests a Seasonal DR Audit:

(i) The ISO shall perform the Seasonal DR Audit at an unannounced time between 0800 and 2200 on non-NERC holiday weekdays within five Business Days of the date of the request.

(ii) The ISO shall initiate the Seasonal DR Audit by issuing a Dispatch Instruction ordering the Demand Response Resource to its Maximum Reduction.

(iii) The ISO shall indicate when issuing the Dispatch Instruction that an audit will be conducted.

(iv) The ISO shall begin the audit with the start of the first five-minute interval after sufficient time has been allowed for the resource to ramp, based on its Demand Reduction Offer parameters, to its Maximum Reduction.

(v) A Market Participant may cancel an audit request prior to issuance of the audit Dispatch Instruction.

(g) If the Seasonal DR Audit is performed by the designation of a period of dispatch after the fact, the designated period must meet all of the requirements in this Section III.1.5.1.3.1 and:

(i) The Market Participant must notify the ISO of its request to use the dispatch to satisfy the Seasonal DR Audit requirement by 5:00 p.m. on the fifth Business Day following the day on which the audit concludes.

(ii) The notification must include the date and time period of the demonstration to be used for the Seasonal DR Audit.

(iii) The demonstration period may begin with the start of any five-minute interval after the completion of the Demand Response Resource Notification Time.

(iv) A CLAIM10 audit or CLAIM30 audit that meets the requirements of a Seasonal DR Audit as provided in this Section III.1.5.1.3.1 may be used to fulfill the Seasonal DR Audit obligation of a Demand Response Resource.

(h) An ISO-Initiated Claimed Capability Audit fulfils the Seasonal DR Audit obligation of a Demand Response Resource.

(i) Each Demand Response Asset associated with a Demand Response Resource is evaluated during the Seasonal DR Audit of the Demand Response Resource.

(j) Any Demand Response Asset on a forced or scheduled curtailment as defined in Section III.8.3 is assessed a zero audit value.

(k) The Seasonal DR Audit value (summer or winter) of a Demand Response Resource resulting from the Seasonal DR Audit shall be the sum of the average demand reductions demonstrated during the audit by each of the Demand Response Resource's constituent Demand Response Assets.

(l) If a Demand Response Asset is added to or removed from a Demand Response Resource between audits, the Demand Response Resource's capability shall be updated to reflect the inclusion or exclusion of the audit value of the Demand Response Asset, such that at any point in time the summer or winter Seasonal DR Audit value of a Demand Response Resource shall equal the sum of the most recent valid like-season audit values of its constituent Demand Response Assets.

(m) The Seasonal DR Audit value shall become effective one calendar day following notification of the audit results to the Market Participant by the ISO.

(n) The summer or winter audit value of a Demand Response Asset shall be set to zero at the end of the Capability Demonstration Year if the Demand Response Asset did not perform a Seasonal DR Audit for that season as part of a Demand Response Resource during that Capability Demonstration Year.

(o) For a Demand Response Asset that was associated with a "Real-Time Demand Response Resource" or a "Real-Time Emergency Generation Resource," as those terms were defined prior to June 1, 2018, any valid result from an audit conducted prior to June 1, 2018 shall continue to be valid on June 1, 2018, and shall retain the same expiration date.

III.1.5.1.4. ISO-Initiated Claimed Capability Audits.

(a) An ISO-Initiated Claimed Capability Audit may be performed by the ISO at any time.

(b) An ISO-Initiated Claimed Capability Audit value shall replace either the summer or winter Seasonal DR Audit value for a Demand Response Resource and shall replace both the winter and summer Establish Claimed Capability Audit values for a Generator Asset, normalized for temperature and steam exports, except:

(i) The Establish Claimed Capability Audit values for a Generator Asset may not exceed the maximum interconnected flow specified in the Network Resource Capability for that resource.

(ii) An ISO-Initiated Claimed Capability Audit value for a Generator Asset shall not set the winter Establish Claimed Capability Audit value unless the ISO-Initiated Claimed Capability Audit was performed at a mean ambient temperature that is less than or equal to 32 degrees Fahrenheit at the Generator Asset location.

(c) If for a Generator Asset a Market Participant submits pressure and relative humidity data for the previous Establish Claimed Capability Audit and the current ISO-Initiated Claimed Capability Audit, the Establish Claimed Capability Audit values derived from the ISO-Initiated Claimed Capability Audit will be normalized to the pressure of the previous Establish Claimed Capability Audit and a relative humidity of 64%.

(d) The audit values derived from the ISO-Initiated Claimed Capability Audit shall become effective one Business Day following notification of the audit results to the Market Participant by the ISO.

(e) To conduct an ISO-Initiated Claimed Capability Audit, the ISO shall:

(i) Initiate an ISO-Initiated Claimed Capability Audit by issuing a Dispatch Instruction ordering the Generator Asset to its Real-Time High Operating Limit or the Demand Response Resource to its Maximum Reduction.

(ii) Indicate when issuing the Dispatch Instruction that an audit will be conducted.

(iii) For Generator Assets, begin the audit with the first full clock hour after sufficient time has been allowed for the Generator Asset to ramp, based on its offered ramp rate, from its current operating point to its Real-Time High Operating Limit.

(iv) For Demand Response Resources, begin the audit with the first five-minute interval after sufficient time has been allowed for the resource to ramp, based on its Demand Reduction Offer parameters, to its Maximum Reduction.

(f) An ISO-Initiated Claimed Capability Audit shall be performed for the following contiguous duration:

Duration Required for an ISO-Initiated Claimed Capability Audit	
Type	**Claimed Capability Audit Duration (Hrs)**
Steam Turbine (Includes Nuclear)	4
Combined Cycle	4

Integrated Coal Gasification Combustion Cycle	4
Pressurized Fluidized Bed Combustion	4
Combustion Gas Turbine	1
Internal Combustion Engine	1
Hydraulic Turbine – Reversible (Electric Storage) Hydraulic Turbine – Other	2
Hydro-Conventional Daily Pondage Hydro-Conventional Run of River Hydro-Conventional Weekly	2
Wind Photovoltaic Fuel Cell	2
Other Electric Storage (Excludes Hydraulic Turbine – Reversible)	2
Demand Response Resource	1

(g) The ISO, in consultation with the Market Participant, will determine the contiguous audit duration for an Asset or Resource type not listed in Section III.1.5.1.4(f).

III.1.5.2 ISO-Initiated Parameter Auditing.

(a) The ISO may perform an audit of any Supply Offer, Demand Reduction Offer or other operating parameter that impacts the ability of a Generator Asset or Demand Response Resource to provide real-time energy or reserves.

(b) Generator audits shall be performed using the following methods for the relevant parameter:

(i) **Economic Maximum Limit**. The Generator Asset shall be evaluated based upon its ability to achieve the current offered Economic Maximum Limit value, through a review of historical dispatch data or based on a response to a current ISO-issued Dispatch Instruction.

(ii) **Manual Response Rate**. The Generator Asset shall be evaluated based upon its ability to respond to Dispatch Instructions at its offered Manual Response Rate, including hold points and changes in Manual Response Rates.

(iii) **Start-Up Time**. The Generator Asset shall be evaluated based upon its ability to achieve the offered Start-Up Time.

(iv) **Notification Time**. The Generator Asset shall be evaluated based upon its ability to close its output breaker within its offered Notification Time.

(v) **CLAIM10**. The Generator Asset shall be evaluated based upon its ability to reach its CLAIM10 in accordance with Section III.9.5.

(vi) **CLAIM30**. The Generator Asset shall be evaluated based upon its ability to reach its CLAIM30 in accordance with Section III.9.5.

(vii) **Automatic Response Rate**. The Generator Asset shall be analyzed, based upon a review of historical performance data, for its ability to respond to four-second electronic Dispatch Instructions.

(viii) **Dual Fuel Capability**. A Generator Asset that is capable of operating on multiple fuels may be required to audit on a specific fuel, as set out in Section III.1.5.2(f).

(c) Demand Response Resource audits shall be performed using the following methods:

(i) **Maximum Reduction**. The Demand Response Resource shall be evaluated based upon its ability to achieve the current offered Maximum Reduction value, through a review of historical dispatch data or based on a response to a current Dispatch Instruction.

(ii) **Demand Response Resource Ramp Rate**. The Demand Response Resource shall be evaluated based upon its ability to respond to Dispatch Instructions at its offered Demand Response Resource Ramp Rate.

(iii) **Demand Response Resource Start-Up Time**. The Demand Response Resource shall be evaluated based upon its ability to achieve its Minimum Reduction within the offered Demand Response Resource Start-Up Time, in response to a Dispatch Instruction and after completing its Demand Response Resource Notification Time.

(iv) **Demand Response Resource Notification Time**. The Demand Response Resource shall be evaluated based upon its ability to start reducing demand within its offered Demand Response Resource Notification Time, from the receipt of a Dispatch Instruction when the Demand Response Resource was not previously reducing demand.

(v) **CLAIM10**. The Demand Response Resource shall be evaluated based upon its ability to reach its CLAIM10 in accordance with Section III.9.5.

(vi) **CLAIM30**. The Demand Response Resource shall be evaluated based upon its ability to reach its CLAIM30 in accordance with Section III.9.5.

(d) To conduct an audit based upon historical data, the ISO shall:

(i) Obtain data through random sampling of generator or Demand Response Resource performance in response to Dispatch Instructions; or

(ii) Obtain data through continual monitoring of generator or Demand Response Resource performance in response to Dispatch Instructions.

(e) To conduct an unannounced audit, the ISO shall initiate the audit by issuing a Dispatch Instruction ordering the Generator Asset or Demand Response Resource to change from the current operating level to a level that permits the ISO to evaluate the performance of the Generator Asset or Demand Response Resource for the parameters being audited.

(f) To conduct an audit of the capability of a Generator Asset described in Section III.1.5.2(b)(viii) to run on a specific fuel:

(i) The ISO shall notify the Lead Market Participant if a Generator Asset is required to undergo an audit on a specific fuel. The ISO, in consultation with the Lead Market Participant, shall develop a plan for the audit.

(ii) The Lead Market Participant will have the ability to propose the time and date of the audit within the ISO's prescribed time frame and must notify the ISO at least five Business Days in advance of the audit, unless otherwise agreed to by the ISO and the Lead Market Participant.

(g) To the extent that the audit results indicate a Market Participant is providing Supply Offer, Demand Reduction Offer or other operating parameter values that are not representative of the actual capability of the Generator Asset or Demand Response Resource, the values for the Generator Asset or Demand Response Resource shall be restricted to those values that are supported by the audit.

(h) In the event that a Generator Asset or Demand Response Resource has had a parameter value restricted:

(i) The Market Participant may submit a restoration plan to the ISO to restore that parameter. The restoration plan shall:

1. Provide an explanation of the discrepancy;
2. Indicate the steps that the Market Participant will take to re-establish the parameter's value;
3. Indicate the timeline for completing the restoration; and
4. Explain the testing that the Market Participant will undertake to verify restoration of the parameter value upon completion.

(ii) The ISO shall:

1. Accept the restoration plan if implementation of the plan, including the testing plan, is reasonably likely to support the proposed change in the parameter value restriction;
2. Coordinate with the Market Participant to perform required testing upon completion of the restoration; and
3. Modify the parameter value restriction following completion of the restoration plan, based upon tested values.

III.1.5.3 Reactive Capability Audits.

(a) Two types of Reactive Capability Audits may be performed:

(i) A lagging Reactive Capability Audit, which is an audit that measures a Reactive Resource's ability to provide reactive power to the transmission system at a specified real power output or consumption.

(ii) A leading Reactive Capability Audit, which is an audit that measures a Reactive Resource's ability to absorb reactive power from the transmission system at a specified real power output or consumption.

(b) The ISO shall develop a list of Reactive Resources that must conduct Reactive Capability Audits. The list shall include Reactive Resources that: (i) have a gross individual nameplate rating greater than 20 MVA; (ii) are directly connected, or are connected through equipment designed primarily for delivering real or reactive power to an interconnection point, to the transmission system at a voltage of 100 kV or above; and (iii) are not exempted from providing voltage control by the ISO. Additional criteria to be used in adding a Reactive Resource to the list includes, but is not limited to, the effect of the Reactive Resource on System Operating Limits, Interconnection Reliability Operating Limits, and local area voltage limits during the following operating states: normal, emergency, and system restoration.

(c) Unless otherwise directed by the ISO, Reactive Resources that are required to perform Reactive Capability Audits shall perform both a lagging Reactive Capability Audit and a leading Reactive Capability Audit.

(d) All Reactive Capability Audits shall meet the testing conditions specified in the ISO New England Operating Documents.

(e) The Reactive Capability Audit value of a Reactive Resource shall reflect any limitations based upon the interdependence of common elements between two or more Reactive Resources such as: auxiliaries, limiting operating parameters, and the deployment of operating personnel.

(f) A Reactive Capability Audit may be denied or rescheduled by the ISO if conducting the Reactive Capability Audit could jeopardize the reliable operation of the electrical system.

(g) Reactive Capability Audits shall be conducted at least every five years, unless otherwise required by the ISO. The ISO may require a Reactive Resource to conduct Reactive Capability Audits more often than every five years if:

(i) there is a change in the Reactive Resource that may affect the reactive power capability of the Reactive Resource;

(ii) there is a change in electrical system conditions that may affect the achievable reactive power output or absorption of the Reactive Resource; or

(iii) historical data shows that the amount of reactive power that the Reactive Resource can provide to or absorb from the transmission system is higher or lower than the latest audit data.

(h) A Lead Market Participant or Transmission Owner may request a waiver of the requirement to conduct a Reactive Capability Audit for its Reactive Resource. The ISO, at its sole discretion, shall determine whether and for how long a waiver may be granted.

III.1.6 [Reserved.]

III.1.6.1 [Reserved.]

III.1.6.2 [Reserved.]

III.1.6.3 [Reserved.]

III.1.6.4 ISO New England Manuals and ISO New England Administrative Procedures.

The ISO shall prepare, maintain and update the ISO New England Manuals and ISO New England Administrative Procedures consistent with the ISO New England Filed Documents. The ISO New England Manuals and ISO New England Administrative Procedures shall be available for inspection by the Market Participants, regulatory authorities with jurisdiction over the ISO or any Market Participant, and the public.

III.1.7 General.

III.1.7.1 Provision of Market Data to the Commission.

The ISO will electronically deliver to the Commission, on an ongoing basis and in a form and manner consistent with its collection of data and in a form and manner acceptable to the Commission, data related to the markets that it administers, in accordance with the Commission's regulations.

III.1.7.2 [Reserved.]

III.1.7.3 Agents.

A Market Participant may participate in the New England Markets through an agent, provided that such Market Participant informs the ISO in advance in writing of the appointment of such agent. A Market Participant using an agent shall be bound by all of the acts or representations of such agent with respect to transactions in the New England Markets, and shall ensure that any such agent complies with the

requirements of the ISO New England Manuals and ISO New England Administrative Procedures and the ISO New England Filed Documents.

III.1.7.4 [Reserved.]

III.1.7.5 Transmission Constraint Penalty Factors.

In the Day-Ahead Energy Market, the Transmission Constraint Penalty Factor for an interface constraint is $10,000/MWh and the Transmission Constraint Penalty Factor for all other transmission constraints is $30,000/MWh. In the Real-Time Energy Market, the Transmission Constraint Penalty Factor for any transmission constraint is $30,000/MWh. Transmission Constraint Penalty Factors are not used in calculating Locational Marginal Prices.

III.1.7.6 Scheduling and Dispatching.

(a) The ISO shall schedule Day-Ahead and schedule and dispatch in Real-Time Resources economically on the basis of least-cost, security-constrained dispatch and the prices and operating characteristics offered by Market Participants. The ISO shall schedule and dispatch sufficient Resources of the Market Participants to serve the New England Markets energy purchase requirements under normal system conditions of the Market Participants and meet the requirements of the New England Control Area for ancillary services provided by such Resources. The ISO shall use a joint optimization process to serve Real-Time Energy Market energy requirements and meet Real-Time Operating Reserve requirements based on a least-cost, security-constrained economic dispatch. Commencing on June 1, 2024, the ISO shall use a joint optimization process to serve Day-Ahead Energy Market energy requirements and Day-Ahead Ancillary Services requirements based on a security-constrained economic commitment and dispatch.

(b) In the event that one or more Resources cannot be scheduled in the Day-Ahead Energy Market on the basis of a least-cost, security-constrained economic commitment and dispatch as a result of one or more Self-Schedule offers contributing to a transmission limit violation, the following scheduling protocols will apply:

> (i) When a single Self-Schedule offer contributes to a transmission limit violation, the Self-Schedule offer will not be scheduled for the entire Self-Schedule period in development of Day-Ahead schedules.

(ii) When two Self-Schedule offers contribute to a transmission limit violation, parallel clearing solutions will be executed such that, for each solution, one of the Self-Schedule offers will be omitted for its entire Self-Schedule period. The least cost solution will be used for purposes of determining which Resources are scheduled in the Day-Ahead Energy Market.

(iii) When three or more Self-Schedule offers contribute to a transmission limit violation, the ISO will determine the total daily MWh for each Self-Schedule offer and will omit Self-Schedule offers in their entirety, in sequence from the offer with the least total daily MWh to the offer with the greatest total MWh, stopping when the transmission limit violation is resolved.

(c) Scheduling and dispatch shall be conducted in accordance with the ISO New England Filed Documents.

(d) The ISO shall undertake, together with Market Participants, to identify any conflict or incompatibility between the scheduling or other deadlines or specifications applicable to the New England Markets, and any relevant procedures of another Control Area, or any tariff (including the Transmission, Markets and Services Tariff). Upon determining that any such conflict or incompatibility exists, the ISO shall propose tariff or procedural changes, or undertake such other efforts as may be appropriate, to resolve any such conflict or incompatibility.

III.1.7.7 Energy Pricing.

The price paid for energy, including demand reductions, bought and sold by the ISO in the New England Markets will reflect the Locational Marginal Price at each Location, determined by the ISO in accordance with the ISO New England Filed Documents. Congestion Costs, which shall be determined by differences in the Congestion Component of Locational Marginal Prices caused by constraints, shall be calculated and collected, and the resulting revenues disbursed, by the ISO in accordance with this Market Rule 1. Loss costs associated with Pool Transmission Facilities, which shall be determined by the differences in Loss Components of the Locational Marginal Prices shall be calculated and collected, and the resulting revenues disbursed, by the ISO in accordance with this Market Rule 1.

III.1.7.8 Market Participant Resources.

A Market Participant may elect to Self-Schedule its Resources in accordance with and subject to the limitations and procedures specified in this Market Rule 1 and the ISO New England Manuals.

III.1.7.8A Day-Ahead Ancillary Services Prices.

The prices paid by the ISO for the provision of Day-Ahead Ancillary Services in the New England Markets will reflect Day-Ahead Ancillary Services clearing prices determined by the ISO in accordance with the ISO New England Filed Documents.

III.1.7.9 Real-Time Reserve Prices.

The price paid by the ISO for the provision of Real-Time Operating Reserve in the New England Markets will reflect Real-Time Reserve Clearing Prices determined by the ISO in accordance with the ISO New England Filed Documents for the system and each Reserve Zone.

III.1.7.10 Other Transactions.

Market Participants may enter into internal bilateral transactions and External Transactions for the purchase or sale of energy or other products to or from each other or any other entity, subject to the obligations of Market Participants to make resources with a Capacity Supply Obligation available for dispatch by the ISO. External Transactions that contemplate the physical transfer of energy or obligations to or from a Market Participant shall be reported to and coordinated with the ISO in accordance with this Market Rule 1 and the ISO New England Manuals.

III.1.7.11 Seasonal Claimed Capability of a Generating Capacity Resource.

(a) A Seasonal Claimed Capability value must be established and maintained for all Generating Capacity Resources. A summer Seasonal Claimed Capability is established for use from June 1 through September 30 and a winter Seasonal Claimed Capability is established for use from October 1 through May 31.

(b) The Seasonal Claimed Capability of a Generating Capacity Resource is the sum of the Seasonal Claimed Capabilities of the Generator Assets that are associated with the Generating Capacity Resource.

(c) The Seasonal Claimed Capability of a Generator Asset is:

(i) Based upon review of historical data for non-intermittent daily cycle hydro.

(ii) The median net real power output during reliability hours, as described in Section III.13.1.2.2.2, for (1) intermittent facilities, and (2) net-metered and special qualifying facilities that do not elect to audit, as reflected in hourly revenue metering data.

(iii) For non-intermittent net-metered and special qualifying facilities that elect to audit, the minimum of (1) the Generator Asset's current Seasonal Claimed Capability Audit value, as performed

pursuant to Section III.1.5.1.3; (2) the Generator Asset's current Establish Claimed Capability Audit value; and (3) the median hourly availability during hours ending 2:00 p.m. through 6:00 p.m. each day of the preceding June through September for Summer and hours ending 6:00 p.m. and 7:00 p.m. each day of the preceding October through May for Winter. The hourly availability:

a. For a Generator Asset that is available for commitment and following Dispatch Instructions, shall be the asset's Economic Maximum Limit, as submitted or redeclared.
b. For a Generator Asset that is off-line and not available for commitment shall be zero.
c. For a Generator Asset that is on-line but not able to follow Dispatch Instructions, shall be the asset's metered output.

(iv) For all other Generator Assets, the minimum of: (1) the Generator Asset's current Establish Claimed Capability Audit value and (2) the Generator Asset's current Seasonal Claimed Capability Audit value, as performed pursuant to Section III.1.5.1.3.

III.1.7.12 Seasonal DR Audit Value of an Active Demand Capacity Resource.

(a) A Seasonal DR Audit value must be established and maintained for all Active Demand Capacity Resources. A summer Seasonal DR Audit value is established for use from April 1 through November 30 and a winter Seasonal DR Audit value is established for use from December 1 through March 31.

(b) The Seasonal DR Audit value of an Active Demand Capacity Resource is the sum of the Seasonal DR Audit values of the Demand Response Resources that are associated with the Active Demand Capacity Resource.

III.1.7.13 [Reserved.]

III.1.7.14 [Reserved.]

III.1.7.15 [Reserved.]

III.1.7.16 [Reserved.]

III.1.7.17 Operating Reserve.

The ISO shall endeavor to procure and maintain an amount of Operating Reserve in Real-Time equal to the system and zonal Operating Reserve requirements as specified in the ISO New England Manuals and ISO New England Administrative Procedures. Reserve requirements for the Forward Reserve Market are determined in accordance with the methodology specified in Section III.9.2 of Market Rule 1. Operating

Reserve requirements for Real-Time dispatch within an Operating Day are determined in accordance with Market Rule 1 and ISO New England Operating Procedure No. 8, Operating Reserve and Regulation.

III.1.7.18 Ramping.

A Generator Asset, Dispatchable Asset Related Demand, or Demand Response Resource dispatched by the ISO pursuant to a control signal appropriate to increase or decrease the Resource's megawatt output, consumption, or demand reduction level shall be able to change output, consumption, or demand reduction at the ramping rate specified in the Offer Data submitted to the ISO for that Resource and shall be subject to sanctions for failure to comply as described in **Appendix B**.

III.1.7.19 Real-Time Reserve Designation.

The ISO shall determine the Real-Time Reserve Designation for each eligible Resource in accordance with this Section III.1.7.19. The Real-Time Reserve Designation shall consist of a MW value, in no case less than zero, for each Operating Reserve product: Ten-Minute Spinning Reserve, Ten-Minute Non-Spinning Reserve, and Thirty-Minute Operating Reserve.

III.1.7.19.1 Eligibility.

To be eligible to receive a Real-Time Reserve Designation, a Resource must meet all of the criteria enumerated in this Section III.1.7.19.1. A Resource that does not meet all of these criteria is not eligible to provide Operating Reserve and will not receive a Real-Time Reserve Designation.

(1) The Resource must be a Dispatchable Resource located within the metered boundaries of the New England Control Area and capable of receiving and responding to electronic Dispatch Instructions.

(2) The Resource must not be part of the first contingency supply loss.

(3) The Resource must not be designated as constrained by transmission limitations.

(4) The Resource's Operating Reserve, if activated, must be sustainable for at least one hour from the time of activation. (This eligibility requirement does not affect a Resource's obligation to follow Dispatch Instructions, even after one hour from the time of activation.)

(5) The Resource must comply with the applicable standards and requirements for provision and dispatch of Operating Reserve as specified in the ISO New England Manuals and ISO New England Administrative Procedures.

III.1.7.19.2 Calculation of Real-Time Reserve Designation.

III.1.7.19.2.1 Generator Assets.

III.1.7.19.2.1.1 On-line Generator Assets.

The Manual Response Rate used in calculations in this section shall be the lesser of the Generator Asset's offered Manual Response Rate and its audited Manual Response Rate as described in Section III.1.5.2.

(a) **Ten-Minute Spinning Reserve.** For an on-line Generator Asset (other than one registered as being composed of multiple generating units whose synchronized capability cannot be determined by the ISO), Ten-Minute Spinning Reserve shall be calculated as the increase in output the Generator Asset could achieve, relative to its current telemetered output, within ten minutes given its Manual Response Rate (and in no case to a level greater than its Economic Maximum Limit). For an on-line Generator Asset registered as being composed of multiple generating units whose synchronized capability cannot be determined by the ISO, Ten-Minute Spinning Reserve shall be zero.

(b) **Ten-Minute Non-Spinning Reserve.** For an on-line Generator Asset (other than one registered as being composed of multiple generating units whose synchronized capability cannot be determined by the ISO), Ten-Minute Non-Spinning Reserve shall be zero. For an on-line Generator Asset registered as being composed of multiple generating units whose synchronized capability cannot be determined by the ISO, Ten-Minute Non-Spinning Reserve shall be calculated as the increase in output the Generator Asset could achieve, relative to its current telemetered output, within ten minutes given its Manual Response Rate (and in no case to a level greater than its Economic Maximum Limit).

(c) **Thirty-Minute Operating Reserve.** For an on-line Generator Asset, Thirty-Minute Operating Reserve shall be calculated as the increase in output the Generator Asset could achieve, relative to its current telemetered output, within thirty minutes given its Manual Response Rate (and in no case greater than its Economic Maximum Limit) minus the Ten-Minute Spinning Reserve quantity calculated for the Generator Asset pursuant to subsection (a) above and the Ten-Minute Non-Spinning Reserve quantity calculated for the Generator Asset pursuant to subsection (b) above.

III.1.7.19.2.1.2 Off-line Generator Assets.

For an off-line Generator Asset that is not a Fast Start Generator, all components of the Real-Time Reserve Designation shall be zero.

(a) **Ten-Minute Spinning Reserve.** For an off-line Fast Start Generator, Ten-Minute Spinning Reserve shall be zero.

(b) **Ten-Minute Non-Spinning Reserve.** For an off-line Fast Start Generator, Ten-Minute Non-Spinning Reserve shall be calculated as the minimum of the Fast Start Generator's Offered CLAIM10, its CLAIM10, and its Economic Maximum Limit (provided, however, that during the Fast Start Generator's Minimum Down Time, the Fast Start Generator's Ten-Minute Non-Spinning Reserve shall be zero, except during the last ten minutes of its Minimum Down Time, at which time the ISO will prorate the Fast Start Generator's Ten-Minute Non-Spinning Reserve to account for the remaining amount of time until the Fast Start Generator's Minimum Down Time expires).

(c) **Thirty-Minute Operating Reserve.** For an off-line Fast Start Generator, Thirty-Minute Operating Reserve shall be calculated as: (i) the minimum of the Fast Start Generator's Offered CLAIM30, its CLAIM30, and its Economic Maximum Limit (provided, however, that during the Fast Start Generator's Minimum Down Time, the Fast Start Generator's Thirty-Minute Operating Reserve shall be zero, except during the last thirty minutes of its Minimum Down Time, at which time the ISO will prorate the Fast Start Generator's Thirty-Minute Operating Reserve to account for the remaining amount of time until the Fast Start Generator's Minimum Down Time expires), minus (ii) the Ten-Minute Non-Spinning Reserve quantity calculated for the Fast Start Generator pursuant to subsection (b) above.

III.1.7.19.2.2 Dispatchable Asset Related Demand.

III.1.7.19.2.2.1 Storage DARDs.

(a) **Ten-Minute Spinning Reserve.** For a Storage DARD, Ten-Minute Spinning Reserve shall be calculated as the absolute value of the amount of current telemetered consumption.

(b) **Ten-Minute Non-Spinning Reserve.** For a Storage DARD, Ten-Minute Non-Spinning Reserve shall be zero.

(c) **Thirty-Minute Operating Reserve.** For a Storage DARD, Thirty-Minute Operating Reserve shall be zero.

III.1.7.19.2.2.2 Dispatchable Asset Related Demand Other Than Storage DARDs.

(a) **Ten-Minute Spinning Reserve.** For a Dispatchable Asset Related Demand (other than a Storage DARD) that has no Controllable Behind-the-Meter Generation, Ten-Minute Spinning Reserve shall be calculated as the decrease in consumption that the Dispatchable Asset Related Demand could achieve, relative to its current telemetered consumption, within ten minutes given its ramp rate (and in no case to an amount less than its Minimum Consumption Limit). For a Dispatchable Asset Related Demand (other than a Storage DARD) having Controllable Behind-the-Meter Generation, Ten-Minute Spinning Reserve shall be zero.

(b) **Ten-Minute Non-Spinning Reserve.** For a Dispatchable Asset Related Demand (other than a Storage DARD) that has no Controllable Behind-the-Meter Generation, Ten-Minute Non-Spinning Reserve shall be zero. For a Dispatchable Asset Related Demand (other than a Storage DARD) having Controllable Behind-the-Meter Generation, Ten-Minute Non-Spinning Reserve shall be calculated as the decrease in consumption that the Dispatchable Asset Related Demand could achieve, relative to its current telemetered consumption, within ten minutes given its ramp rate (and in no case to an amount less than its Minimum Consumption Limit).

(c) **Thirty-Minute Operating Reserve.** For a Dispatchable Asset Related Demand (other than a Storage DARD) that has no Controllable Behind-the-Meter Generation, Thirty-Minute Operating Reserve shall be calculated as the decrease in consumption that the Dispatchable Asset Related Demand could achieve, relative to its current telemetered consumption, within thirty minutes given its ramp rate (and in no case to an amount less than its Minimum Consumption Limit) minus the Ten-Minute Spinning Reserve quantity calculated for the Dispatchable Asset Related Demand pursuant to subsection (a) above. For a Dispatchable Asset Related Demand (other than a Storage DARD) having Controllable Behind-the-Meter Generation, Thirty-Minute Operating Reserve shall be calculated as the decrease in consumption that the Dispatchable Asset Related Demand could achieve, relative to its current telemetered consumption, within thirty minutes given its ramp rate (and in no case to an amount less than its Minimum Consumption Limit)

minus the Ten-Minute Non-Spinning Reserve quantity calculated for the Dispatchable Asset Related Demand pursuant to subsection (b) above.

III.1.7.19.2.3 Demand Response Resources.

For a Demand Response Resource that does not provide one-minute telemetry to the ISO, notwithstanding any provision in this Section III.1.7.19.2.3 to the contrary, the Ten-Minute Spinning Reserve and Ten-Minute Non-Spinning Reserve components of the Real-Time Reserve Designation shall be zero. The Demand Response Resource Ramp Rate used in calculations in this section shall be the lesser of the Resource's offered Demand Response Resource Ramp Rate and its audited Demand Response Resource Ramp Rate as described in Section III.1.5.2.

III.1.7.19.2.3.1 Dispatched.

(a) **Ten-Minute Spinning Reserve.** For a Demand Response Resource that is being dispatched and that has no Controllable Behind-the-Meter Generation, Ten-Minute Spinning Reserve shall be calculated as the increase in demand reduction that the Demand Response Resource could achieve, relative to the estimated current demand reduction level, within ten minutes given its Demand Response Resource Ramp Rate (and in no case greater than its Maximum Reduction). For a Demand Response Resource that is being dispatched and that has Controllable Behind-the-Meter Generation, Ten-Minute Spinning Reserve shall be zero.

(b) **Ten-Minute Non-Spinning Reserve.** For a Demand Response Resource that is being dispatched and that has no Controllable Behind-the-Meter Generation, Ten-Minute Non-Spinning Reserve shall be zero. For a Demand Response Resource that is being dispatched and that has Controllable Behind-the-Meter Generation, Ten-Minute Non-Spinning Reserve shall be calculated as the increase in demand reduction that the Demand Response Resource could achieve, relative to the estimated current demand reduction level, within ten minutes given its Demand Response Resource Ramp Rate (and in no case greater than its Maximum Reduction).

(c) **Thirty-Minute Operating Reserve.** For a Demand Response Resource that is being dispatched, Thirty-Minute Operating Reserve shall be calculated as the increase in demand reduction that the Demand Response Resource could achieve, relative to the estimated current demand reduction level, within thirty minutes given its Demand Response Resource Ramp Rate (and in no case greater than its Maximum Reduction) minus the Ten-Minute Spinning Reserve quantity

calculated for the Resource pursuant to subsection (a) above and the Ten-Minute Non-Spinning Reserve quantity calculated for the Resource pursuant to subsection (b) above.

III.1.7.19.2.3.2 Non-Dispatched.

For a Demand Response Resource that is not being dispatched that is not a Fast Start Demand Response Resource, all components of the Real-Time Reserve Designation shall be zero.

(a) **Ten-Minute Spinning Reserve.** For a Fast Start Demand Response Resource that is not being dispatched, Ten-Minute Spinning Reserve shall be zero.

(b) **Ten-Minute Non-Spinning Reserve.** For a Fast Start Demand Response Resource that is not being dispatched, Ten-Minute Non-Spinning Reserve shall be calculated as the minimum of the Demand Response Resource's Offered CLAIM10, its CLAIM10, and its Maximum Reduction.

(c) **Thirty-Minute Operating Reserve.** For a Fast Start Demand Response Resource that is not being dispatched, Thirty-Minute Operating Reserve shall be calculated as: (i) the minimum of the Demand Response Resource's Offered CLAIM30, its CLAIM30, and its Maximum Reduction, minus (ii) the Ten-Minute Non-Spinning Reserve quantity calculated for the Demand Response Resource pursuant to subsection (b) above.

III.1.7.20 Information and Operating Requirements.

(a) [Reserved.]

(b) Market Participants selling from Resources within the New England Control Area shall: supply to the ISO all applicable Offer Data; report to the ISO Resources that are Self-Scheduled; report to the ISO External Transaction sales; confirm to the ISO bilateral sales to Market Participants within the New England Control Area; respond to the ISO's directives to start, shutdown or change output, consumption, or demand reduction levels of Generator Assets, DARDs, or Demand Response Resources, change scheduled voltages or reactive output levels; continuously maintain all Offer Data concurrent with on-line operating information; and ensure that, where so equipped, equipment is operated with control equipment functioning as specified in the ISO New England Manuals and ISO New England Administrative Procedures.

(c) Market Participants selling from Resources outside the New England Control Area shall: provide to the ISO all applicable Offer Data, including offers specifying amounts of energy available, hours of availability and prices of energy and other services; respond to ISO directives to schedule delivery or change delivery schedules; and communicate delivery schedules to the source Control Area and any intermediary Control Areas.

(d) Market Participants, as applicable, shall: respond or ensure a response to ISO directives for load management steps; report to the ISO all bilateral purchase transactions including External Transaction purchases; and respond or ensure a response to other ISO directives such as those required during Emergency operation.

(e) Market Participant, as applicable, shall provide to the ISO requests to purchase specified amounts of energy for each hour of the Operating Day during which it intends to purchase from the Day-Ahead Energy Market.

(f) Market Participants are responsible for reporting to the ISO anticipated availability and other information concerning Generator Assets, Demand Response Resources and Dispatchable Asset Related Demands required by the ISO New England Operating Documents, including but not limited to the Market Participant's ability to procure fuel and physical limitations that could reduce Resource output or demand reduction capability for the pertinent Operating Day.

III.1.8 Energy Call Option Offers and Day-Ahead Ancillary Services Demand Quantities.

III.1.8.1 Applicability.

The provisions of this Section III.1.8 apply commencing on June 1, 2024.

III.1.8.2 Energy Call Option Offers.

Market Participants may submit Energy Call Option Offers for the Operating Day as specified in this Section III.1.8.2.

(a) Each Energy Call Option Offer shall be associated with a specific Generator Asset or Demand Response Resource for which the Market Participant has submitted a corresponding Supply Offer or Demand Reduction Offer in the Day-Ahead Energy Market for the same hour of the Operating Day.

(b) Each Energy Call Option Offer shall specify: (i) the hour of the Operating Day for which the Energy Call Option Offer applies; (ii) an offer price, in $/MWh, that is greater than or equal to zero; and (iii) an offer quantity, in MWh, that is greater than or equal to zero. The offer price shall not exceed the Reserve Constraint Penalty Factor value specified in Section III.2.6.2(b)(vi) of this Market Rule 1. The offer quantity shall not exceed the Economic Maximum Limit specified in the associated Supply Offer or the Maximum Reduction specified in the associated Demand Reduction Offer.

(c) For each hour of the Operating Day, a Market Participant may submit only one Energy Call Option Offer associated with a specific Generator Asset or Demand Response Resource.

(d) Energy Call Option Offers shall be submitted by the offer submission deadline for the Day-Ahead Energy Market specified in Section III.1.10.1A of this Market Rule 1. An Energy Call Option Offer shall not remain in effect for subsequent Operating Days.

III.1.8.3 Energy Call Option Strike Price.

For each hour of the Operating Day, the ISO shall specify the Energy Call Option Strike Price in $/MWh. The value of the Energy Call Option Strike Price shall represent a forecast of the expected hourly Real-Time Hub Price for each hour of the Operating Day.

The forecast used to determine the Energy Call Option Strike Price shall be based on a publicly-available forecasting algorithm. The ISO shall identify the publicly-available forecasting algorithm and shall review any potential revisions to the forecasting process, prospectively, through the stakeholder process.

The ISO shall post, publicly, the value of the Energy Call Option Strike Price for each hour of the Operating Day no later than two hours before the offer submission deadline for the Day-Ahead Energy Market specified in Section III.1.10.1A of this Market Rule 1, or such other time as necessary to account for software failures or other events.

III.1.8.4 [Reserved.]

III.1.8.5 Day-Ahead Ancillary Services Demand Quantities.

The Day-Ahead Energy Market shall endeavor to procure the demand quantities for the Day-Ahead Ancillary Services specified in this Section III.1.8.5.

(a) For each hour of the Operating Day, the Day-Ahead Ten-Minute Spinning Reserve Demand Quantity shall be equal to the projected Ten-Minute Spinning Reserve Requirement as described in Section III.2.7A of this Market Rule 1 and ISO New England Operating Procedure No. 8.

(b) For each hour of the Operating Day, the Day-Ahead Total Ten-Minute Reserve Demand Quantity shall be equal to the projected Ten-Minute Reserve Requirement as described in Section III.2.7A of this Market Rule 1 and ISO New England Operating Procedure No. 8.

(c) For each hour of the Operating Day, the Day-Ahead Total Thirty-Minute Operating Reserve Demand Quantity shall be equal to the projected Minimum Total Reserve Requirement as described in Section III.2.7A of this Market Rule 1 and ISO New England Operating Procedure No. 8.

(d) For each hour of the Operating Day, the Day-Ahead Total Ninety-Minute Reserve Demand Quantity shall be the sum of (i) the reserve capability sufficient to satisfy the requirements in NERC Reliability Standard BAL-002-3 – Disturbance Control Standard – Contingency Reserve for Recovery from a Balancing Contingency Event, including the restoration of Contingency Reserve within the Contingency Reserve Restoration Period, and (ii) an allowance for load forecast error.

(e) For each hour of the Operating Day, the Day-Ahead Total Four-Hour Reserve Demand Quantity shall be equal to the sum of (i) the reserve capability sufficient to satisfy the requirements of NPCC Regional Reliability Reference Directory No. 5 Reserve, including the restoration of Thirty-Minute Operating Reserve within four hours of a deficiency, and (ii) an allowance for load forecast error.

(f) For each hour of the Operating Day, the Day-Ahead Energy Imbalance Reserve Demand Quantity shall be determined during the scheduling of the Day-Ahead Energy Market. The Day-Ahead Energy Imbalance Reserve Demand Quantity shall be equal to the greater of (a) zero or (b) the value of:
(i) the Forecast Energy Requirement Demand Quantity; less (ii) the sum of the total MWh of all Supply Offers and the total MWh of all Demand Reduction Offers that receive the forecast energy requirement credit, as specified in Section III.3.2.1(q)(5); less (iii) the net total External Transactions (imports minus exports, in MWh) scheduled in the Day-Ahead Energy Market.

III.1.8.6 Forecast Energy Requirement Demand Quantity.

For each hour of the Operating Day, the Forecast Energy Requirement Demand Quantity shall be equal to the ISO forecast for the total loads in the New England Control Area produced pursuant to Section III.1.10.1.A(h) of this Market Rule 1.

III.1.9 Pre-scheduling.

III.1.9.1 Offer and Bid Caps and Cost Verification for Offers and Bids.

III.1.9.1.1 Cost Verification of Resource Offers.

The incremental energy values of Supply Offers and Demand Response Resources above $1,000/MWh for any Resource other than an External Resource are subject to the following cost verification requirements. Unless expressly stated otherwise, cost verification is utilized in all pricing, commitment, dispatch and settlement determinations. For purposes of the following requirements, Reference Levels are calculated using the procedures in Section III.A.7.5 for calculating cost-based Reference Levels.

(a) If the incremental energy value of a Resource's offer is greater than the incremental energy Reference Level value of the Resource, then the incremental energy value in the offer is replaced with the greater of the Reference Level for incremental energy or $1,000/MWh.

(b) For purposes of the price calculations in Sections III.2.5 and III.2.7A, if the adjusted offer calculated under Section III.2.4 for a Rapid Response Pricing Asset is greater than $1,000/MWh (after the incremental energy value is evaluated under Section III.1.9.1.1(a) above), then verification will be performed as follows using a Reference Level value calculated with the adjusted offer formulas specified in Section III.2.4.

(i) If the Reference Level value is less than or equal to $1,000/MWh, then the adjusted offer for the Resource is set at $1,000/MWh;

(ii) If the Reference Level value is greater than $1,000/MWh, then the adjusted offer for the Resource is set at the lower of the Reference Level value and the adjusted offer.

III.1.9.1.2 Offer and Bid Caps.

(a) For purposes of the price calculations described in Section III.2 and for purposes of scheduling a Resource in the Day-Ahead Energy Market in accordance with Section III.1.7.6 following the commitment of the Resource, the incremental energy value of an offer is capped at $2,000/MWh.

(b) Demand Bids shall not specify a bid price below the Energy Offer Floor or above the Demand Bid Cap.

(c) Supply Offers shall not specify an offer price (for incremental energy) below the Energy Offer Floor.

(d) External Transactions shall not specify a price below the External Transaction Floor or above the External Transaction Cap.

(e) Increment Offers and Decrement Bids shall not specify an offer or bid price below the Energy Offer Floor or above the Virtual Cap.

III.1.9.2 [Reserved.]

III.1.9.3 [Reserved.]

III.1.9.4 [Reserved.]

III.1.9.5 [Reserved.]

III.1.9.6 [Reserved.]

III.1.9.7 Market Participant Responsibilities.

Market Participants authorized and intending to request market-based Start-Up Fees and No-Load Fee in their Offer Data shall submit a specification of such fees to the ISO for each Generator Asset as to which the Market Participant intends to request such fees. Any such specification shall identify the applicable period and be submitted on or before the applicable deadline and shall remain in effect unless otherwise modified in accordance with Section III.1.10.9. The ISO shall reject any request for Start-Up Fees and No-Load Fee in a Market Participant's Offer Data that does not conform to the Market Participant's specification on file with the ISO.

III.1.9.8 [Reserved.]

III.1.10 Scheduling.

III.1.10.1 General.

(a) The ISO shall administer scheduling processes to implement a Day-Ahead Energy Market and a Real-Time Energy Market.

(b) The Day-Ahead Energy Market shall enable Market Participants to purchase and sell energy and, commencing on June 1, 2024, sell ancillary services through the New England Markets at the applicable Day-Ahead Prices, and enable Market Participants to submit External Transactions conditioned upon

Congestion Costs not exceeding a specified level. Market Participants whose purchases and sales and External Transactions are scheduled in the Day-Ahead Energy Market shall be obligated to purchase or sell energy or pay Congestion Costs and costs for losses, at the applicable Day-Ahead Prices for the amounts scheduled.

(c) In the Real-Time Energy Market,

(i) Market Participants that deviate from the amount of energy purchases or sales scheduled in the Day-Ahead Energy Market shall replace the energy not delivered with energy from the Real-Time Energy Market or an internal bilateral transaction and shall pay for such energy not delivered, net of any internal bilateral transactions, at the applicable Real-Time Price, unless otherwise specified by this Market Rule 1, and

(ii) Non-Market Participant Transmission Customers shall be obligated to pay Congestion Costs and costs for losses for the amount of the scheduled transmission uses in the Real-Time Energy Market at the applicable Real-Time Congestion Component and Loss Component price differences, unless otherwise specified by this Market Rule 1.

(d) The following scheduling procedures and principles shall govern the commitment of Resources to the Day-Ahead Energy Market and the Real-Time Energy Market over a period extending from one week to one hour prior to the Real-Time dispatch. Scheduling encompasses the Day-Ahead and hourly scheduling process, through which the ISO determines the Day-Ahead Energy Market schedule and determines, based on changing forecasts of conditions and actions by Market Participants and system constraints, a plan to serve the hourly energy and reserve requirements of the New England Control Area in the least costly manner, subject to maintaining the reliability of the New England Control Area. Scheduling of External Transactions in the Real-Time Energy Market is subject to Section II.44 of the OATT.

(e) If the ISO's forecast for the next seven days projects a likelihood of Emergency Condition, the ISO may commit, for all or part of such seven day period, to the use of Generator Assets or Demand Response Resources with Notification Time greater than 24 hours as necessary in order to alleviate or mitigate such Emergency, in accordance with the Market Participants' binding Supply Offers or Demand Reduction Offers.

III.1.10.1A Energy Market Scheduling.

The submission of Day-Ahead offers and bids shall occur not later than 10:00 a.m. on the day before the Operating Day for which transactions are being scheduled, or such other deadline as may be specified by the ISO in order to comply with the practical requirements and the economic and efficiency objectives of the scheduling process specified in this Market Rule 1.

(a) **Locational Demand Bids –** Each Market Participant may submit to the ISO specifications of the amount and location of its customer loads and/or energy purchases to be included in the Day-Ahead Energy Market for each hour of the next Operating Day, such specifications to comply with the requirements set forth in the ISO New England Manuals and ISO New England Administrative Procedures. Each Market Participant shall inform the ISO of (i) the prices, if any, at which it desires not to include its load in the Day-Ahead Energy Market rather than pay the applicable Day-Ahead Price, (ii) hourly schedules for Resources Self-Scheduled by the Market Participant; and (iii) the Decrement Bid at which each such Self-Scheduled Resource will disconnect or reduce output, or confirmation of the Market Participant's intent not to reduce output. Price-sensitive Demand Bids and Decrement Bids must be greater than zero MW and shall not exceed the Demand Bid Cap and Virtual Cap.

(b) **External Transactions –** All Market Participants shall submit to the ISO schedules for any External Transactions involving use of Generator Assets or the New England Transmission System as specified below, and shall inform the ISO whether the transaction is to be included in the Day-Ahead Energy Market. Any Market Participant that elects to include an External Transaction in the Day-Ahead Energy Market may specify the price (such price not to exceed the maximum price that may be specified in the ISO New England Manuals and ISO New England Administrative Procedures), if any, at which it will be curtailed rather than pay Congestion Costs. The foregoing price specification shall apply to the price difference between the Locational Marginal Prices for specified External Transaction source and sink points in the Day-Ahead scheduling process only. Any Market Participant that deviates from its Day-Ahead External Transaction schedule or elects not to include its External Transaction in the Day-Ahead Energy Market shall be subject to Congestion Costs in the Real-Time Energy Market in order to complete any such scheduled External Transaction. Scheduling of External Transactions shall be conducted in accordance with the specifications in the ISO New England Manuals and ISO New England Administrative Procedures and the following requirements:

(i) Market Participants shall submit schedules for all External Transaction purchases for delivery within the New England Control Area from Resources outside the New England Control Area;

(ii) Market Participants shall submit schedules for External Transaction sales to entities outside the New England Control Area from Resources within the New England Control Area;

(iii) In the Day-Ahead Energy Market, if the sum of all submitted Self-Scheduled External Transaction purchases less External Transaction sales exceeds the import capability associated with the applicable External Node, the offer prices for all Self-Scheduled External Transaction purchases at the applicable External Node shall be set equal to the Energy Offer Floor;

(iv) In the Day-Ahead Energy Market, if the sum of all submitted Self-Scheduled External Transaction sales less External Transaction purchases exceeds the export capability associated with the applicable External Node, the offer prices for all Self-Scheduled External Transaction sales at the applicable External Node shall be set equal to the External Transaction Cap;

(v) The ISO shall not consider Start-Up Fees, No-Load Fees, Notification Times or any other inter-temporal parameters in scheduling or dispatching External Transactions.

(c) **Generator Asset Supply Offers –** Market Participants selling into the New England Markets from Generator Assets may submit Supply Offers for the supply of energy for the following Operating Day.

Such Supply Offers:

(i) Shall specify the Resource and Blocks (price and quantity of Energy) for each hour of the Operating Day for each Resource offered by the Market Participant to the ISO. The prices and quantities in a Block may each vary on an hourly basis;

(ii) If based on energy from a Generator Asset internal to the New England Control Area, may specify, for Supply Offers, a Start-Up Fee and No-Load Fee for each hour of the Operating Day. Start-Up Fee and No-Load Fee may vary on an hourly basis;

(iii) Shall specify, for Supply Offers from a dual-fuel Generator Asset, the fuel type. The fuel type may vary on an hourly basis. A Market Participant that submits a Supply Offer using the higher cost fuel type must satisfy the consultation requirements for dual-fuel Generator Assets in Section III.A.3 of Appendix A;

(iv) Shall specify a Minimum Run Time to be used for commitment purposes that does not exceed 24 hours;

(v) Supply Offers shall constitute an offer to submit the Generator Asset to the ISO for commitment and dispatch in accordance with the terms of the Supply Offer, where such Supply Offer, with regard to operating limits, shall specify changes, including to the Economic Maximum Limit, Economic Minimum Limit and Emergency Minimum Limit, from those submitted as part of the Resource's Offer Data to reflect the physical operating characteristics and/or availability of the Resource (except that for a Limited Energy Resource, the Economic Maximum Limit may be revised to reflect an energy (MWh) limitation), which offer shall remain open through the Operating Day for which the Supply Offer is submitted; and

(vi) Shall, in the case of a Supply Offer from a Generator Asset associated with an Electric Storage Facility, also meet the requirements specified in Section III.1.10.6.

(d) DARD Demand Bids – Market Participants participating in the New England Markets with Dispatchable Asset Related Demands may submit Demand Bids for the consumption of energy for the following Operating Day.

Such Demand Bids:

(i) Shall specify the Dispatchable Asset Related Demand and Blocks (price and Energy quantity pairs) for each hour of the Operating Day for each Dispatchable Asset Related Demand offered by the Market Participant to the ISO. The prices and quantities in a Block may each vary on an hourly basis;

(ii) Shall constitute an offer to submit the Dispatchable Asset Related Demand to the ISO for commitment and dispatch in accordance with the terms of the Demand Bid, where such Demand Bid, with regard to operating limits, shall specify changes, including to the Maximum Consumption Limit and Minimum Consumption Limit, from those submitted as part of the

Resource's Offer Data to reflect the physical operating characteristics and/or availability of the Resource;

(iii) Shall specify a Minimum Consumption Limit that is less than or equal to its Nominated Consumption Limit; and

(iv) Shall, in the case of a Demand Bid from a Storage DARD, also meet the requirements specified in Section III.1.10.6.

(e) **Demand Response Resource Demand Reduction Offers –** Market Participants selling into the New England Markets from Demand Response Resources may submit Demand Reduction Offers for the supply of energy for the following Operating Day. A Demand Reduction Offer shall constitute an offer to submit the Demand Response Resource to the ISO for commitment and dispatch in accordance with the terms of the Demand Reduction Offer. Demand Reduction Offers:

(i) Shall specify the Demand Response Resource and Blocks (price and demand reduction quantity pairs) for each hour of the Operating Day. The prices and demand reduction quantities may vary on an hourly basis.

(ii) Shall not specify a price that is above the Energy Offer Cap, below the Energy Offer Floor, or below the Demand Reduction Threshold Price in effect for the Operating Day. For purposes of clearing the Day-Ahead and Real-Time Energy Markets and calculating Day-Ahead and Real-Time Locational Marginal Prices and Real-Time Reserve Clearing Prices, any price specified below the Demand Reduction Threshold price in effect for the Operating Day will be considered to be equal to the Demand Reduction Threshold Price for the Operating Day.

(iii) Shall not include average avoided peak transmission or distribution losses in the demand reduction quantity.

(iv) May specify an Interruption Cost for each hour of the Operating Day, which may vary on an hourly basis.

(v) Shall specify a Minimum Reduction Time to be used for scheduling purposes that does not exceed 24 hours.

(vi) Shall specify a Maximum Reduction amount no greater than the sum of the Maximum Interruptible Capacities of the Demand Response Resource's operational Demand Response Assets.

(vii) Shall specify changes to the Maximum Reduction and Minimum Reduction from those submitted as part of the Demand Response Resource's Offer Data to reflect the physical operating characteristics and/or availability of the Demand Response Resource.

(f) **Demand Reduction Threshold Price –** The Demand Reduction Threshold Price for each month shall be determined through an analysis of a smoothed, historic supply curve for the month. The historic supply curve shall be derived from Real-Time generator and import Offer Data (excluding Coordinated External Transactions) for the same month of the previous year. The ISO may adjust the Offer Data to account for significant changes in generator and import availability or other significant changes to the historic supply curve. The historic supply curve shall be calculated as follows:

(a) Each generator and import offer Block (i.e., each price-quantity pair offered in the Real-Time Energy Market) for each day of the month shall be compiled and sorted in ascending order of price to create an unsmoothed supply curve.

(b) An unsmoothed supply curve for the month shall be formed from the price and cumulative quantity of each offer Block.

(c) A non-linear regression shall be performed on a sampled portion of the unsmoothed supply curve to produce an increasing, convex, smooth approximation of the supply curve.

(d) A historic threshold price P_{th} shall be determined as the point on the smoothed supply curve beyond which the benefit to load from the reduced LMP resulting from the demand reduction of Demand Response Resources exceeds the cost to load associated with compensating Demand Response Resources for demand reduction.

(e) The Demand Reduction Threshold Price for the upcoming month shall be determined by the following formula:

$$DRTP = P_{th} X — \frac{FPI_c}{FPI_h}$$

where FPI_h is the historic fuel price index for the same month of the previous year, and FPI_c is the fuel price index for the current month.

The historic and current fuel price indices used to establish the Demand Reduction Threshold Price for a month shall be based on the lesser of the monthly natural gas or heating oil fuel indices applicable to the New England Control Area, as calculated three business days before the start of the month preceding the Demand Reduction Threshold Price's effective date.

The ISO will post the Demand Reduction Threshold Price, along with the index-based fuel price values used in establishing the Demand Reduction Threshold Price, on its website by the 15th day of the month preceding the Demand Reduction Threshold Price's effective date.

(g) **Subsequent Operating Days** – Each Supply Offer, Demand Reduction Offer, or Demand Bid by a Market Participant of a Resource shall remain in effect for subsequent Operating Days until superseded or canceled except in the case of an External Transaction purchase, in which case, the Supply Offer shall remain in effect for the applicable Operating Day and shall not remain in effect for subsequent Operating Days. Hourly overrides of a Supply Offer, a Demand Reduction Offer, or a Demand Bid shall remain in effect only for the applicable Operating Day.

(h) **Load Estimate** – The ISO shall post on the internet the total hourly loads including Decrement Bids scheduled in the Day-Ahead Energy Market, as well as the ISO's estimate of the Control Area hourly load for the next Operating Day.

(i) **Prorated Supply** – In determining Day-Ahead schedules, in the event of multiple marginal Supply Offers, Demand Reduction Offers, Increment Offers and/or External Transaction purchases at a pricing location, the ISO shall clear the marginal Supply Offers, Demand Reduction Offers, Increment Offers and/or External Transaction purchases proportional to the amount of energy (MW) from each marginal offer and/or External Transaction at the pricing location. The Economic Maximum Limits, Economic Minimum Limits, Minimum Reductions and Maximum Reductions are not used in determining the amount of energy (MW) in each marginal Supply Offer or Demand Reduction Offer to be cleared on a pro-rated basis. However, the Day-Ahead schedules resulting from the pro-ration process will reflect Economic Maximum Limits, Economic Minimum Limits, Minimum Reductions and Maximum Reductions.

(j) **Prorated Demand** – In determining Day-Ahead schedules, in the event of multiple marginal Demand Bids, Decrement Bids and/or External Transaction sales at a pricing location, the ISO shall clear the marginal Demand Bids, Decrement Bids and/or External Transaction sales proportional to the amount of energy (MW) from each marginal bid and/or External Transaction at the pricing location.

(k) **Virtuals** – All Market Participants may submit Increment Offers and/or Decrement Bids that apply to the Day-Ahead Energy Market only. Such offers and bids must comply with the requirements set forth in the ISO New England Manuals and ISO New England Administrative Procedures and must specify amount, location and price, if any, at which the Market Participant desires to purchase or sell energy in the Day-Ahead Energy Market.

(l) **Energy Call Option Offers** – Market Participants selling into the New England Markets from Generator Assets or Demand Response Resources may submit Energy Call Option Offers for the following Operating Day. Energy Call Option Offers shall be submitted to the ISO in accordance with Section III.1.8.2 of this Market Rule 1.

III.1.10.2 Pool-Scheduled Resources.

Pool-Scheduled Resources are those Resources for which Market Participants submitted Supply Offers, Demand Reduction Offers, or Demand Bids in the Day-Ahead Energy Market and which the ISO scheduled in the Day-Ahead Energy Market as well as Generator Assets, DARDs or Demand Response Resources committed by the ISO subsequent to the Day-Ahead Energy Market. Such Resources shall be committed to provide or consume energy in the Real-Time dispatch unless the schedules for such Resources are revised pursuant to Sections III.1.10.9 or III.1.11. Pool-Scheduled Resources shall be governed by the following principles and procedures.

(a) Pool-Scheduled Resources shall be selected by the ISO on the basis of the prices offered for energy supply or consumption and related services, Start-Up Fees, No-Load Fees, Interruption Cost and the specified operating characteristics, offered by Market Participants.

(b) The ISO shall optimize the dispatch of energy, and commencing on June 1, 2024, energy and ancillary services, from Limited Energy Resources by request to minimize the as-bid production cost for the New England Control Area. In implementing the use of Limited Energy Resources, the ISO shall use its best efforts to select the most economic hours of operation for Limited Energy Resources, in order to make optimal use of such Resources in the Day-Ahead Energy Market consistent with the Supply Offers and Demand Reduction Offers of other Resources, the submitted Demand Bids and Decrement Bids, and ancillary services requirements procured pursuant to this Market Rule 1.

(c) Market Participants offering energy from facilities with fuel or environmental limitations may submit data to the ISO that is sufficient to enable the ISO to determine the available operating hours of such facilities.

(d) Market Participants shall make available their Pool-Scheduled Resources to the ISO for coordinated operation to supply the needs of the New England Control Area for energy and ancillary services.

III.1.10.3 Self-Scheduled Resources.

A Resource that is Self-Scheduled shall be governed by the following principles and procedures. The minimum duration of a Self-Schedule for a Generator Asset or DARD shall not result in the Generator Asset or DARD operating for less than its Minimum Run Time. A Generator Asset that is online as a result of a Self-Schedule will be dispatched above its Economic Minimum Limit based on the economic merit of its Supply Offer. A DARD that is consuming as a result of a Self-Schedule may be dispatched above its Minimum Consumption Limit based on the economic merit of its Demand Bid. A Demand Response Resource shall not be Self-Scheduled.

III.1.10.4 External Resources.

Market Participants with External Resources may submit External Transactions as detailed in Section III.1.10.7 and Section III.1.10.7.A of this Market Rule 1.

III.1.10.5 Dispatchable Asset Related Demand.

(a) External Transactions that are sales to an external Control Area are not eligible to be Dispatchable Asset Related Demands.

(b) A Market Participant with a Dispatchable Asset Related Demand in the New England Control Area must:

(i) notify the ISO of any outage (including partial outages) that may reduce the Dispatchable Asset Related Demand's ability to respond to Dispatch Instructions and the expected return date from the outage;

(ii) in accordance with the ISO New England Manuals and Operating Procedures, perform audit tests and submit the results to the ISO or provide to the ISO appropriate historical production data;

(iii) abide by the ISO maintenance coordination procedures; and

(iv) provide information reasonably requested by the ISO, including the name and location of the Dispatchable Asset Related Demand.

III.1.10.6 Electric Storage

A storage facility is a facility that is capable of receiving electricity from the grid and storing the energy for later injection of electricity back to the grid. A storage facility may participate in the New England Markets as described below.

(a) A storage facility that satisfies the requirements of this subsection (a) may participate in the New England Markets as an Electric Storage Facility. An Electric Storage Facility shall:

(i) comprise one or more storage facilities at the same point of interconnection;

(ii) have the ability to inject at least 0.1 MW and consume at least 0.1 MW;

(iii) be directly metered;

(iv) be registered as, and subject to all rules applicable to, a dispatchable Generator Asset;

(v) be registered as, and subject to all rules applicable to, a DARD that represents the same equipment as the Generator Asset;

(vi) settle its injection of electricity to the grid as a Generator Asset and its receipt of electricity from the grid as a DARD;

(vii) not be precluded from providing retail services so long as it is able to fulfill its wholesale Energy Market and Forward Capacity Market obligations including, but not limited to, satisfying meter data reporting requirements and notifying the ISO of any changes to operational capabilities; and

(viii) meet the requirements of either a Binary Storage Facility or a Continuous Storage Facility, as described in subsections (b) and (c) below.

(b) A storage facility that satisfies the requirements of this subsection (b) may participate in the New England Markets as a Binary Storage Facility. A Binary Storage Facility shall:

(i) satisfy the requirements applicable to an Electric Storage Facility; and

(ii) offer its Generator Asset and DARD into the Energy Market as Rapid Response Pricing Assets; and

(iii) be issued Dispatch Instructions in a manner that ensures the facility is not required to consume and inject simultaneously.

(c) A storage facility that satisfies the requirements of this subsection (c) may participate in the New England Markets as a Continuous Storage Facility. A Continuous Storage Facility shall:

(i) satisfy the requirements applicable to an Electric Storage Facility;

(ii) be registered as, may provide Regulation as, and is subject to all rules applicable to, an ATRR that represents the same equipment as the Generator Asset and DARD;

(iii) be capable of transitioning between the facility's maximum output and maximum consumption (and vice versa) in ten minutes or less;

(iv) not utilize storage capability that is shared with another Generator Asset, DARD or ATRR;

(v) specify in Supply Offers a zero MW value for Economic Minimum Limit and Emergency Minimum Limit (except for Generator Assets undergoing Facility and Equipment Testing or auditing); a zero time value for Minimum Run Time, Minimum Down Time, Notification Time, and Start-Up Time; and a zero cost value for Start-Up Fee and No-Load Fee;

(vi) specify in Demand Bids a zero MW value for Minimum Consumption Limit (except for DARDs undergoing Facility and Equipment Testing or auditing) and a zero time value for Minimum Run Time and Minimum Down Time;

(vii) be Self-Scheduled in the Day-Ahead Energy Market and Real-Time Energy Market, and operate in an on-line state, unless the facility is declared unavailable by the Market Participant; and

(viii) be issued a combined dispatch control signal equal to the Desired Dispatch Point (of the Generator Asset) minus the Desired Dispatch Point (of the DARD) plus the AGC SetPoint (of the ATRR).

(d) A storage facility shall comply with all applicable registration, metering, and accounting rules including, but not limited to, the following:

(i) A Market Participant wishing to purchase energy from the ISO-administered wholesale markets must first, jointly with its Host Participant, register one or more wholesale Load Assets with the ISO as described in ISO New England Manual M-28 and ISO New England Manual M-RPA; where the Market Participant wishes to register an Electric Storage Facility, the registered Load Asset must be a DARD.

(ii) A storage facility's charging load shall not qualify as a DARD if the Host Participant is unwilling or unable to support the registration, metering, and accounting of the storage facility's load as a separate and distinct Load Asset. A storage facility registered as a DARD will be charged the nodal Locational Marginal Price by the ISO and the Market Participant will not pay twice for the same charging load.

(iii) The registration and metering of all Assets must comply with ISO New England Operating Procedure No. 14 and ISO New England Operating Procedure No. 18, including with the requirement that an Asset's revenue metering must comply with the accuracy requirements found in ISO New England Operating Procedure No. 18.

(iv) Pursuant to ISO New England Manual M-28, the Assigned Meter Reader, the Host Participant, and the ISO provide the data for use in the daily settlement process within the timelines described in the manual. The data may be five-minute interval data, and may be no more than hourly data, as described in Section III.3.2 and in ISO New England Manual M-28.

(v) Based on the Metered Quantity For Settlement and the Locational Marginal Price in the settlement interval, the ISO shall conduct all Energy Market accounting pursuant to Section III.3.2.1.

(e) A facility registered as a dispatchable Generator Asset, an ATRR, and a DARD that each represent the same equipment must participate as a Continuous Storage Facility.

(f) A storage facility not participating as an Electric Storage Facility may, if it satisfies the associated requirements, be registered as a Generator Asset (including a Settlement Only Resource) for settlement of its injection of electricity to the grid and as an Asset Related Demand for settlement of its wholesale load.

(g) A storage facility may, if it satisfies the associated requirements, be registered as a Demand Response Asset. (As described in Section III.8.1.1, a Demand Response Asset and a Generator Asset may not be registered at the same end-use customer facility unless the Generator Asset is separately metered and reported and its output does not reduce the load reported at the Retail Delivery Point of the Demand Response Asset.)

(h) A storage device may, if it satisfies the associated requirements, be registered as a component of either an On-Peak Demand Resource or a Seasonal Peak Demand Resource.

(i) A storage facility may, if it satisfies the associated requirements, provide Regulation pursuant to Section III.14.

III.1.10.7 External Transactions.

The provisions of this Section III.1.10.7 do not apply to Coordinated External Transactions.

(a) Market Participants that submit an External Transaction in the Day-Ahead Energy Market must also submit a corresponding External Transaction in the Real-Time Energy Market in order to be eligible for scheduling in the Real-Time Energy Market. Priced External Transactions for the Real-Time Energy Market must be submitted by the offer submission deadline for the Day-Ahead Energy Market.

(b) Priced External Transactions submitted in both the Day-Ahead Energy Market and the Real-Time Energy Market will be treated as Self-Scheduled External Transactions in the Real-Time Energy Market for the associated megawatt amounts that cleared the Day-Ahead Energy Market, unless the Market Participant modifies the price component of its Real-Time offer during the Re-Offer Period.

(c) Any External Transaction, or portion thereof, submitted to the Real-Time Energy Market that did not clear in the Day-Ahead Energy Market will not be scheduled in Real-Time if the ISO anticipates that the External Transaction would create or worsen an Emergency. External Transactions cleared in the Day-Ahead Energy Market and associated with a Real-Time Energy Market submission will continue to be scheduled in Real-Time prior to and during an Emergency, until the procedures governing the Emergency, as set forth in ISO New England Operating Procedure No. 9, require a change in schedule.

(d) External Transactions submitted to the Real-Time Energy Market must contain the associated e-Tag ID and transmission reservation, if required, at the time the transaction is submitted to the Real-Time Energy Market.

(e) [Reserved.]

(f) External Transaction sales meeting all of the criteria for any of the transaction types described in (i) through (iv) below receive priority in the scheduling and curtailment of transactions as set forth in Section II.44 of the OATT. External Transaction sales meeting all of the criteria for any of the transaction types described in (i) through (iv) below are referred to herein and in the OATT as being supported in Real-Time.

(i) Capacity Export Through Import Constrained Zone Transactions:

(1) The External Transaction is exporting across an external interface located in an import-constrained Capacity Zone that cleared in the Forward Capacity Auction with price separation, as determined in accordance with Section III.12.4 and Section III.13.2.3.4 of Market Rule 1;

(2) The External Transaction is directly associated with an Export Bid or Administrative Export De-List Bid that cleared in the Forward Capacity Auction, and the megawatt amount of the External Transaction is less than or equal to the megawatt amount of the cleared Export Bid;

(3) The External Node associated with the cleared Export Bid or Administrative Export De-List Bid is connected to the import-constrained Capacity Zone, and is not connected to a Capacity Zone that is not import-constrained;

(4) The Resource, or portion thereof, that is associated with the cleared Export Bid or Administrative Export De-List Bid is not located in the import-constrained Capacity Zone;

(5) The External Transaction has been submitted and cleared in the Day-Ahead Energy Market;

(6) A matching External Transaction has also been submitted into the Real-Time Energy Market by the end of the Re-Offer Period for Self-Scheduled External Transactions, and, in accordance with Section III.1.10.7(a), by the offer submission deadline for the Day-Ahead Energy Market for priced External Transactions.

(ii) FCA Cleared Export Transactions:

(1) The External Transaction sale is exporting to an External Node that is connected only to an import-constrained Reserve Zone;

(2) The External Transaction sale is directly associated with an Export Bid or an Administrative Export De-List Bid that cleared in the Forward Capacity Auction, and the megawatt amount of the External Transaction is less than or equal to the megawatt amount of the cleared Export Bid;

(3) The Resource, or portion thereof, without a Capacity Supply Obligation associated with the Export Bid or Administrative Export De-List Bid is located outside the import-constrained Reserve Zone;

(4) The External Transaction sale is submitted and cleared in the Day-Ahead Energy Market;

(5) A matching External Transaction has also been submitted into the Real-Time Energy Market by the end of the Re-Offer Period for Self-Scheduled External Transactions, and, in accordance with Section III.1.10.7(a), by the offer submission deadline for the Day-Ahead Energy Market for priced External Transactions.

(iii) Same Reserve Zone Export Transactions:

(1) A Resource, or portion thereof, without a Capacity Supply Obligation is associated with the External Transaction sale, and the megawatt amount of the External Transaction is less than or equal to the portion of the Resource without a Capacity Supply Obligation;

(2) The External Node of the External Transaction sale is connected only to the same Reserve Zone in which the associated Resource, or portion thereof, without a Capacity Supply Obligation is located;

(3) The Resource, or portion thereof, without a Capacity Supply Obligation is Self-Scheduled in the Real-Time Energy Market and online at a megawatt level greater than or equal to the External Transaction sale's megawatt amount;

(4) Neither the External Transaction sale nor the portion of the Resource without a Capacity Supply Obligation is required to offer into the Day-Ahead Energy Market.

(iv) Unconstrained Export Transactions:

(1) A Resource, or portion thereof, without a Capacity Supply Obligation is associated with the External Transaction sale, and the megawatt amount of the External Transaction is less than or equal to the portion of the Resource without a Capacity Supply Obligation;

(2) The External Node of the External Transaction sale is not connected only to an import-constrained Reserve Zone;

(3) The Resource, or portion thereof, without a Capacity Supply Obligation is not separated from the External Node by a transmission interface constraint as determined in Sections III.12.2.1(b) and III.12.2.2(b) of Market Rule 1 that was binding in the Forward Capacity Auction in the direction of the export;

(4) The Resource, or portion thereof, without a Capacity Supply Obligation is Self-Scheduled in the Real-Time Energy Market and online at a megawatt level greater than or equal to the External Transaction sale's megawatt amount;

(5) Neither the External Transaction sale, nor the portion of the Resource without a Capacity Supply Obligation is required to offer into the Day-Ahead Energy Market.

(g) Treatment of External Transaction sales in ISO commitment for local second contingency protection.

(i) Capacity Export Through Import Constrained Zone Transactions and FCA Cleared Export Transactions: The transaction's export demand that clears in the Day-Ahead Energy Market will be explicitly considered as load in the exporting Reserve Zone by the ISO when committing Resources to provide local second contingency protection for the associated Operating Day.

(ii) The export demand of External Transaction sales not meeting the criteria in (i) above is not considered by the ISO when planning and committing Resources to provide local second contingency protection, and is assumed to be zero.

(iii) Same Reserve Zone Export Transactions and Unconstrained Export Transactions: If a Resource, or portion thereof, without a Capacity Supply Obligation is committed to be online during the Operating Day either through clearing in the Day-Ahead Energy Market or through Self-Scheduling subsequent to the Day-Ahead Energy Market and a Same Reserve Zone Export Transaction or Unconstrained Export Transaction is submitted before the end of the Re-Offer Period designating that Resource as supporting the transaction, the ISO will not utilize the portion of the Resource without a Capacity Supply Obligation supporting the export transaction to meet local second contingency protection requirements. The eligibility of Resources not meeting the foregoing criteria to be used to meet local second contingency protection requirements shall be in accordance with the relevant provisions of the ISO New England System Rules.

(h) Allocation of costs to Capacity Export Through Import Constrained Zone Transactions and FCA Cleared Export Transactions: Market Participants with Capacity Export Through Import Constrained Zone Transactions and FCA Cleared Export Transactions shall incur a proportional share of the charges described below, which are allocated to Market Participants based on Day-Ahead Load Obligation or Real-Time Load Obligation. The share shall be determined by including the Day-Ahead Load Obligation or Real-Time Load Obligation associated with the External Transaction, as applicable, in the total Day-Ahead Load Obligation or Real-Time Load Obligation for the appropriate Reliability Region, Reserve Zone, or Load Zone used in each cost allocation calculation:

(i) NCPC for Local Second Contingency Protection Resources allocated within the exporting Reliability Region, pursuant to Section III.F.3.3.

(ii) Forward Reserve Market charges allocated within the exporting Load Zone, pursuant to Section III.9.9.

(iii) Real-Time Reserve Charges allocated within the exporting Load Zone, pursuant to Section III.10.3.

(i) When action is taken by the ISO to reduce External Transaction sales due to a system wide capacity deficient condition or the forecast of such a condition, and an External Transaction sale designates a Resource, or portion of a Resource, without a Capacity Supply Obligation, to support the transaction, the ISO will review the status of the designated Resource. If the designated Resource is Self-Scheduled and online at a megawatt level greater than or equal to the External Transaction sale, that

External Transaction sale will not be reduced until such time as Regional Network Load within the New England Control Area is also being reduced. When reductions to such transactions are required, the affected transactions shall be reduced pro-rata.

(j) Market Participants shall submit External Transactions as megawatt blocks with intervals of one hour at the relevant External Node. External Transactions will be scheduled in the Day-Ahead Energy Market as megawatt blocks for hourly durations. The ISO may dispatch External Transactions in the Real-Time Energy Market as megawatt blocks for periods of less than one hour, to the extent allowed pursuant to inter-Control Area operating protocols.

III.1.10.7.A Coordinated Transaction Scheduling.

The provisions of this Section III.1.10.7.A apply to Coordinated External Transactions, which are implemented at the New York Northern AC external Location.

(a) Market Participants that submit a Coordinated External Transaction in the Day-Ahead Energy Market must also submit a corresponding Coordinated External Transaction, in the form of an Interface Bid, in the Real-Time Energy Market in order to be eligible for scheduling in the Real-Time Energy Market.

(b) An Interface Bid submitted in the Real-Time Energy Market shall specify a duration consisting of one or more consecutive 15-minute increments. An Interface Bid shall include a bid price, a bid quantity, and a bid direction for each 15-minute increment. The bid price may be positive or negative. An Interface Bid may not be submitted or modified later than 75 minutes before the start of the clock hour for which it is offered.

(c) Interface Bids are cleared in economic merit order for each 15-minute increment, based upon the forecasted real-time price difference across the external interface. The total quantity of Interface Bids cleared shall determine the external interface schedule between New England and the adjacent Control Area. The total quantity of Interface Bids cleared shall depend upon, among other factors, bid production costs of resources in both Control Areas, the Interface Bids of all Market Participants, transmission system conditions, and any real-time operating limits necessary to ensure reliable operation of the transmission system.

(d) All Coordinated External Transactions submitted either to the Day-Ahead Energy Market or the Real-Time Energy Market must contain the associated e-Tag ID at the time the transaction is submitted.

(e) Any Coordinated External Transaction, or portion thereof, submitted to the Real-Time Energy Market will not be scheduled in Real-Time if the ISO anticipates that the External Transaction would create or worsen an Emergency, unless the procedures governing the Emergency, as set forth in ISO New England Operating Procedure No. 9, permit the transaction to be scheduled.

III.1.10.8 ISO Responsibilities.

(a) Scheduling Considerations

(i) Prior to June 1, 2024, the ISO shall use its best efforts to determine (1) the least-cost means of satisfying hourly purchase requests for energy, the projected hourly requirements for Operating Reserve, Replacement Reserve and other ancillary services of the Market Participants, including the reliability requirements of the New England Control Area, of the Day-Ahead Energy Market, and (2) the least-cost means of satisfying the Operating Reserve, Replacement Reserve and other ancillary service requirements for any portion of the load forecast of the ISO for the Operating Day in excess of that scheduled in the Day-Ahead Energy Market.

In making the determinations specified in this subsection (a)(i), the ISO shall take into account: (i) the ISO's forecasts of New England Markets and New England Control Area energy requirements, giving due consideration to the energy requirement forecasts and purchase requests submitted by Market Participants for the Day-Ahead Energy Market; (ii) the offers and bids submitted by Market Participants; (iii) the availability of Limited Energy Resources; (iv) the capacity, location, and other relevant characteristics of Self-Scheduled Resources; (v) the requirements of the New England Control Area for Operating Reserve and Replacement Reserve, as specified in the ISO New England Manuals and ISO New England Administrative Procedures; (vi) the requirements of the New England Control Area for Regulation and other ancillary services, as specified in the ISO New England Manuals and ISO New England Administrative Procedures; (vii) the benefits of avoiding or minimizing transmission constraint control operations, as specified in the ISO New England Manuals and ISO New England Administrative Procedures; and (viii) such other factors as the ISO reasonably concludes are relevant to the foregoing determination. The ISO shall develop a Day-Ahead Energy schedule based on the applicable portions of the foregoing determination, and shall determine the Day-Ahead Prices resulting from such schedule.

(ii) Commencing on June 1, 2024, in scheduling the Day-Ahead Energy Market, the ISO shall use its best efforts to determine the security-constrained economic commitment and dispatch that jointly optimizes: (1) Demand Bids, Decrement Bids, Demand Reduction Offers, Supply Offers, Increment Offers, and External Transactions, for energy; (2) Energy Call Option Offers to satisfy the Day-Ahead Ancillary Services demand quantities; and (3) Supply Offers, Demand Reduction Offers, External Transactions, and Energy Call Option Offers to satisfy the Forecast Energy Requirement Demand Quantity.

In making the determinations specified in this subsection (a)(ii), the ISO shall take into account, as applicable: (1) the ISO's forecasts of New England Markets and New England Control Area energy requirements, giving due consideration to the energy requirement forecasts and purchase requests submitted by Market Participants for the Day-Ahead Energy Market; (2) the offers and bids submitted by Market Participants; (3) the availability of Limited Energy Resources; (4) capacity, location, and other relevant characteristics of Self-Scheduled Resources; (5) the requirements of the New England Control Area for ancillary services; (6) the operational capabilities of any Resource to adjust the output, consumption, or demand reduction within the operating characteristics specified in the Market Participant's Offer Data, Supply Offer, Demand Reduction Offer, or Demand Bid; (7) the benefits of avoiding or minimizing transmission constraint control operations, as specified in the ISO New England Manuals and ISO New England Administrative Procedures; and (8) such other factors as the ISO reasonably concludes are relevant to the foregoing determination.

In scheduling the Day-Ahead Energy Market, the following limitations shall apply:

(1) For purposes of satisfying the demand quantities for Day-Ahead Generation Contingency Reserve or Day-Ahead Replacement Energy Reserve specified in Sections III.1.8.5(a)-(e), the ISO shall not take into account an Energy Call Option Offer unless the Generator Asset or the Demand Response Resource associated with the Energy Call Option Offer meets the eligibility requirements enumerated in Section III.1.7.19.1.

(2) For purposes of satisfying the Day-Ahead Energy Imbalance Reserve Demand Quantity specified in Section III.1.8.5(f), the ISO shall not take into account an Energy Call Option Offer unless the Generator Asset or the Demand Response Resource associated with the Energy Call Option Offer is either (i) scheduled for energy in the Day-Ahead Energy Market for the applicable hour, or (ii) is a Fast Start Generator or Fast Start Demand Response Resource.

(b) Not later than 1:30 p.m. of the day before each Operating Day, or such earlier deadline as may be specified by the ISO in the ISO New England Manuals and ISO New England Administrative Procedures or such later deadline as necessary to account for software failures or other events, the ISO shall: (i) post the aggregate Day-Ahead Energy schedule; (ii) post the Day-Ahead Prices; and (iii) inform the Market Participants of their scheduled injections and withdrawals. In the event of an Emergency, the ISO will notify Market Participants as soon as practicable if the Day-Ahead Energy Market cannot be operated.

(c) Following posting of the information specified in Section III.1.10.8(b), the ISO shall revise its schedule of Resources to reflect updated projections of load, conditions affecting electric system operations in the New England Control Area, the availability of and constraints on limited energy and other Resources, transmission constraints, and other relevant factors. The ISO shall use its best efforts to determine the least-cost means to satisfy any remaining reliability requirements of the New England Control Area for the Operating Day.

(d) Market Participants shall pay and be paid for the quantities of energy scheduled in the Day-Ahead Energy Market at the applicable Day-Ahead Prices.

III.1.10.9 Hourly Scheduling.

(a) Following the initial posting by the ISO of the Locational Marginal Prices resulting from the Day-Ahead Energy Market, and subject to the right of the ISO to schedule and dispatch Resources and to direct that schedules be changed to address an actual or potential Emergency, a Resource Re-Offer Period shall exist from the time of the posting specified in Section III.1.10.8(b) until 2:00 p.m. on the day before each Operating Day or such other Re-Offer Period as necessary to account for software failures or other events. During the Re-Offer Period, Market Participants may submit revisions to Supply Offers, revisions to Demand Reduction Offers, and revisions to Demand Bids for any Dispatchable Asset Related Demand. Resources scheduled subsequent to the closing of the Re-Offer Period shall be settled at the applicable Real-Time Prices, and shall not affect the obligation to pay or receive payment for the quantities of energy scheduled in the Day-Ahead Energy Market at the applicable Day-Ahead Prices.

(b) During the Re-Offer Period, Market Participants may submit revisions to the price of priced External Transactions. External Transactions scheduled subsequent to the closing of the Re-Offer Period shall be settled at the applicable Real-Time Prices, and shall not affect the obligation to pay or receive payment for the quantities of energy scheduled in the Day-Ahead Energy Market at the applicable Day-

Ahead Prices. A submission during the Re-Offer Period for any portion of a transaction that was cleared in the Day-Ahead Energy Market is subject to the provisions in Section III.1.10.7. A Market Participant may request to Self-Schedule an External Transaction and adjust the schedule on an hour-to-hour basis or request to reduce the quantity of a priced External Transaction. The ISO must be notified of the request not later than 60 minutes prior to the hour in which the adjustment is to take effect. The External Transaction re-offer provisions of this Section III.1.10.9(b) shall not apply to Coordinated External Transactions, which are submitted pursuant to Section III.1.10.7.A.

(c) Following the completion of the initial Reserve Adequacy Analysis and throughout the Operating Day, a Market Participant may modify certain Supply Offer or Demand Bid parameters for a Generator Asset or a Dispatchable Asset Related Demand on an hour-to-hour basis, provided that the modification is made no later than 30 minutes prior to the beginning of the hour for which the modification is to take effect:

(i) For a Generator Asset, the Start-Up Fee, the No-Load Fee, the fuel type (for dual-fuel Generator Assets), and the quantity and price pairs of its Blocks may be modified.

(ii) For a Dispatchable Asset Related Demand, the quantity and price pairs of its Blocks may be modified.

(d) Following the completion of the initial Reserve Adequacy Analysis and throughout the Operating Day, a Market Participant may not modify any of the following Demand Reduction Offer parameters: price and demand reduction quantity pairs, Interruption Cost, Demand Response Resource Start-Up Time, Demand Response Resource Notification Time, Minimum Reduction Time, and Minimum Time Between Reductions.

(e) During the Operating Day, a Market Participant may request to Self-Schedule a Generator Asset or Dispatchable Asset Related Demand or may request to cancel a Self-Schedule for a Generator Asset or Dispatchable Asset Related Demand. The ISO will honor the request so long as it will not cause or worsen a reliability constraint. If the ISO is able to honor a Self-Schedule request, a Generator Asset will be permitted to come online at its Economic Minimum Limit and a Dispatchable Asset Related Demand will be dispatched to its Minimum Consumption Limit. A Market Participant may not request to Self-Schedule a Demand Response Resource. A Market Participant may cancel the Self-Schedule of a Continuous Storage Generator Asset or a Continuous Storage DARD only by declaring the facility unavailable.

(f) During the Operating Day, in the event that in a given hour a Market Participant seeks to modify a Supply Offer or Demand Bid after the deadline for modifications specified in Section III.1.10.9(c), then:

(i) the Market Participant may request that a Generator Asset be dispatched above its Economic Minimum Limit at a specified output. The ISO will honor the request so long as it will not cause or worsen a reliability constraint. If the ISO is able to honor the request, the Generator Asset will be dispatched as though it had offered the specified output for the hour in question at the Energy Offer Floor.

(ii) the Market Participant may request that a Dispatchable Asset Related Demand be dispatched above its Minimum Consumption Limit at a specified value. The ISO will honor the request so long as it will not cause or worsen a reliability constraint. If the ISO is able to honor the request, the Dispatchable Asset Related Demand will be dispatched at or above the requested amount for the hour in question.

(g) During the Operating Day, in any interval in which a Generator Asset is providing Regulation, the upper limit of its energy dispatch range shall be reduced by the amount of Regulation Capacity, and the lower limit of its energy dispatch range shall be increased by the amount of Regulation Capacity. Any such adjustment shall not affect the Real-Time Reserve Designation.

(h) During the Operating Day, in any interval in which a Continuous Storage ATRR is providing Regulation, the upper limit of the associated Generator Asset's energy dispatch range shall be reduced by the Regulation High Limit, and the associated DARD's consumption dispatch range shall be reduced by the Regulation Low Limit. Any such adjustment shall not affect the Real-Time Reserve Designation.

(i) For each hour in the Operating Day, as soon as practicable after the deadlines specified in the foregoing subsection of this Section III.1.10, the ISO shall provide Market Participants and parties to External Transactions with any revisions to their schedules for the hour.

III.1.11 Dispatch.

The following procedures and principles shall govern the dispatch of the Resources available to the ISO.

III.1.11.1 Resource Output or Consumption and Demand Reduction.

The ISO shall have the authority to direct any Market Participant to adjust the output, consumption or demand reduction of any Dispatchable Resource within the operating characteristics specified in the Market Participant's Offer Data, Supply Offer, Demand Reduction Offer or Demand Bid. The ISO may cancel its selection of, or otherwise release, Pool-Scheduled Resources. The ISO shall adjust the output, consumption or demand reduction of Resources as necessary: (a) for both Dispatchable Resources and Non-Dispatchable Resources, to maintain reliability, and subject to that constraint, for Dispatchable Resources, (b) to minimize the cost of supplying the energy, reserves, and other services required by the Market Participants and the operation of the New England Control Area; (c) to balance supply and demand, maintain scheduled tie flows, and provide frequency support within the New England Control Area; and (d) to minimize unscheduled interchange that is not frequency related between the New England Control Area and other Control Areas.

III.1.11.2 Operating Basis.

In carrying out the foregoing objectives, the ISO shall conduct the operation of the New England Control Area and shall, in accordance with the ISO New England Manuals and ISO New England Administrative Procedures, (i) utilize available Operating Reserve and replace such Operating Reserve when utilized; and (ii) monitor the availability of adequate Operating Reserve.

III.1.11.3 Dispatchable Resources.

With the exception of Settlement Only Resources, Generator Assets that meet the size criteria to be Settlement Only Resources, External Transactions, nuclear-powered Resources and photovoltaic Resources, all Resources must be Dispatchable Resources in the Energy Market and meet the technical specifications in ISO New England Operating Procedure No. 14 and ISO New England Operating Procedure No. 18 for dispatchability.

A Market Participant that does not meet the requirement for a Dispatchable Resource to be dispatchable in the Energy Market because the Resource is not connected to a remote terminal unit meeting the requirements of ISO New England Operating Procedure No. 18 shall take the following steps:

1. By January 15, 2017, the Market Participant shall submit to the ISO a circuit order form for the primary and secondary communication paths for the remote terminal unit.
2. The Market Participant shall work diligently with the ISO to ensure the Resource is able to receive and respond to electronic Dispatch Instructions within twelve months of the circuit order form submission.

A Market Participant that does not meet the requirement for a Dispatchable Resource to be dispatchable in the Energy Market by the deadline set forth above shall provide the ISO with a written plan for remedying the deficiencies, and shall identify in the plan the specific actions to be taken and a reasonable timeline for rendering the Resource dispatchable. The Market Participant shall complete the remediation in accordance with and under the timeline set forth in the written plan. Until a Resource is dispatchable, it may only be Self-Scheduled in the Real-Time Energy Market and shall otherwise be treated as a Non-Dispatchable Resource.

Dispatchable Resources in the Energy Market are subject to the following requirements:

(a) The ISO shall optimize the dispatch of energy from Limited Energy Resources by request to minimize the as-bid production cost for the New England Control Area. In implementing the use of Limited Energy Resources, the ISO shall use its best efforts to select the most economic hours of operation for Limited Energy Resources, in order to make optimal use of such Resources consistent with the dynamic load-following requirements of the New England Control Area and the availability of other Resources to the ISO.

(b) The ISO shall implement the dispatch of energy from Dispatchable Resources and the designation of Real-Time Operating Reserve to Dispatchable Resources, including the dispatchable portion of Resources which are otherwise Self-Scheduled, by sending appropriate signals and instructions to the entity controlling such Resources. Each Market Participant shall ensure that the entity controlling a Dispatchable Resource offered or made available by that Market Participant complies with the energy dispatch signals and instructions transmitted by the ISO.

(c) The ISO shall have the authority to modify a Market Participant’s operational related Offer Data for a Dispatchable Resource if the ISO observes that the Market Participant’s Resource is not operating in accordance with such Offer Data. The ISO shall modify such operational related Offer Data based on observed performance and such modified Offer Data shall remain in effect until either (i) the affected Market Participant requests a test to be performed, and coordinates the testing pursuant to the procedures specified in the ISO New England Manuals, and the results of the test justify a change to the Market Participant’s Offer Data or (ii) the ISO observes, through actual performance, that modification to the Market Participant’s Offer Data is justified.

(d) Market Participants shall exert all reasonable efforts to operate, or ensure the operation of, their Dispatchable Resources in the New England Control Area as close to dispatched output, consumption or demand reduction levels as practical, consistent with Good Utility Practice.

(e) Settlement Only Resources are not eligible to be DNE Dispatchable Generators.

Wind and hydro Intermittent Power Resources that are not Settlement Only Resources are required to receive and respond to Do Not Exceed Dispatch Points, except as follows:

(i) A wind or hydro Intermittent Power Resource not capable of receiving and responding to electronic Dispatch Instructions will be manually dispatched.

(ii) A Market Participant may elect, but is not required, to have a wind or hydro Intermittent Power Resource that is less than 5 MW and is connected through transmission facilities rated at less than 115 kV be dispatched as a DNE Dispatchable Generator.

(iii) A Market Participant with a hydro Intermittent Power Resource that is able to operate within a dispatchable range and is capable of responding to Dispatch Instructions to increase or decrease output within its dispatchable range may elect to have that resource dispatched as a DDP Dispatchable Resource.

(f) The ISO may request that dual-fuel Generator Assets that normally burn natural gas voluntarily take all necessary steps (within the limitations imposed by the operating limitations of their installed equipment and their environmental and operating permits) to prepare to switch to secondary fuel in anticipation of natural gas supply shortages. The ISO may request that Market Participants with dual-fuel Generator Assets that normally burn natural gas voluntarily switch to a secondary fuel in anticipation of natural gas supply shortages. The ISO may communicate with Market Participants with dual-fuel Generator Assets that normally burn natural gas to verify whether the Market Participants have switched or are planning to switch to an alternate fuel.

III.1.11.4 Emergency Condition.

If the ISO anticipates or declares an Emergency Condition, all External Transaction sales out of the New England Control Area that are not backed by a Resource may be interrupted, in accordance with the ISO New England Manuals, in order to serve load and Operating Reserve in the New England Control Area.

III.1.11.5 Dispatchability Requirements for Intermittent Power Resources.

(a) Intermittent Power Resources that are Dispatchable Resources with Supply Offers that do not clear in the Day-Ahead Energy Market and are not committed by the ISO prior to or during the Operating Day must be Self-Scheduled in the Real-Time Energy Market at the Resource's Economic Minimum Limit in order to operate in Real-Time.

(b) Intermittent Power Resources that are not Settlement Only Resources, are not Dispatchable Resources, and are not committed by the ISO prior to or during the Operating Day must be Self-Scheduled in the Real-Time Energy Market with the Resource's Economic Maximum Limit and Economic Minimum Limit redeclared to the same value in order to operate in Real-Time. Redeclarations must be updated throughout the Operating Day to reflect actual operating capabilities.

III.1.11.6 Non-Dispatchable Resources.

Non-Dispatchable Resources are subject to the following requirements:

(a) The ISO shall have the authority to modify a Market Participant's operational related Offer Data for a Non-Dispatchable Resource if the ISO observes that the Market Participant's Resource is not operating in accordance with such Offer Data. The ISO shall modify such operational related Offer Data based on observed performance and such modified Offer Data shall remain in effect until either (i) the affected Market Participant requests a test to be performed and coordinates the testing pursuant to the procedures specified in the ISO New England Manuals, and the results of the test justify a change to the Market Participant's Offer Data or (ii) the ISO observes, through actual performance, that modification to the Market Participant's Offer Data is justified.

(b) Market Participants with Non-Dispatchable Resources shall exert all reasonable efforts to operate or ensure the operation of their Resources in the New England Control Area as close to dispatched levels as practical when dispatched by the ISO for reliability, consistent with Good Utility Practice.

III.2 Day-Ahead Prices, Real-Time Prices, and Real-Time Reserve Clearing Prices Calculation

III.2.1 Introduction.

The ISO shall calculate the price of energy at Nodes, Load Zones, DRR Aggregation Zones and Hubs in the New England Control Area and at External Nodes on the basis of Locational Marginal Prices and shall calculate the price of Operating Reserve in Real-Time for each Reserve Zone on the basis of Real-Time Reserve Clearing Prices as determined in accordance with this Market Rule 1. Locational Marginal Prices for energy shall be calculated on a Day-Ahead basis for each hour of the Day-Ahead Energy Market, and every five minutes during the Operating Day for the Real-Time Energy Market. Real-Time Reserve Clearing Prices shall be calculated on a Real-Time basis every five minutes as part of the joint optimization of energy and Operating Reserve during the Operating Day. Commencing on June 1, 2024, Day-Ahead Ancillary Services prices and the Forecast Energy Requirement Price shall be calculated for each hour of the Operating Day, as specified in Section III.2.6.2, as part of the joint optimization of energy and ancillary services in the Day-Ahead Energy Market.

III.2.2 General.

The ISO shall determine the least cost security-constrained unit commitment and dispatch, which is the least costly means of serving load at different Locations in the New England Control Area based on scheduled or actual conditions, as applicable, existing on the power grid and on the prices at which Market Participants have offered to supply and consume energy in the New England Markets. Day-Ahead Locational Marginal Prices for energy for the applicable Locations will be calculated based on the unit commitment and economic dispatch and the prices of offers and bids. Real-Time Locational Marginal Prices for energy and Real-Time Reserve Clearing Prices will be calculated based on a jointly optimized economic dispatch of energy and designation of Operating Reserve utilizing the prices of energy offers and bids, and Reserve Constraint Penalty Factors as specified in Section III.2.7A when applicable. Commencing on June 1, 2024, Day-Ahead Locational Marginal Prices for energy, Day-Ahead Ancillary Services prices, and the Forecast Energy Requirement Price will be calculated based on a jointly optimized security-constrained economic commitment and dispatch of energy and Day-Ahead Ancillary Services utilizing the prices of offers and bids, and Reserve Constraint Penalty Factors as specified in Section III.2.6.2(b) when applicable.

Except as further provided in Section III.2.6, the process for the determination of Locational Marginal Prices shall be as follows:

(a) To determine operating conditions, in the Day-Ahead Energy Market or Real-Time Energy Market, on the New England Transmission System, the ISO shall use a computer model of the interconnected grid that uses scheduled quantities or available metered inputs regarding electric output, loads, and power flows to model remaining flows and conditions, producing a consistent representation of power flows on the network. The computer model employed for this purpose in the Real-Time Energy Market, referred to as the State Estimator program, is a standard industry tool and is described in Section III.2.3. It will be used to obtain information regarding the output of resources supplying energy and Operating Reserve to the New England Control Area, loads at busses in the New England Control Area, transmission losses, penalty factors, and power flows on binding transmission and interface constraints for use in the calculation of Day-Ahead and Real-Time Locational Marginal Prices and Real-Time Reserve Clearing Prices, and, commencing on June 1, 2024, Day-Ahead Ancillary Services prices and the Forecast Energy Requirement Price. Additional information used in the calculation of Real-Time Locational Marginal Prices and Real-Time Reserve Clearing Prices, including Offer Data, Real-Time Operating Reserve designations and Real-Time schedules for External Transactions, will be obtained from the ISO's dispatch software and dispatchers.

(b) Using the prices at which Market Participants offer and bid energy to the New England Markets, the ISO shall determine the offers and bids of energy that will be considered in the calculation of Day-Ahead Prices, Real-Time Prices and Real-Time Reserve Clearing Prices. During the Operating Day, Real-Time nodal Locational Marginal Prices and Real-Time Reserve Clearing Prices shall be determined every five minutes and such determinations shall be the basis of the settlement of sales and purchases of energy in the Real-Time Energy Market, the settlement associated with the provision of Operating Reserve in Real-Time and the settlement of Congestion Costs and costs for losses under the Transmission, Markets and Services Tariff not covered by the Day-Ahead Energy Market. As described in Section III.2.6, every offer and bid by a Market Participant that is scheduled in the Day-Ahead Energy Market will be utilized in the calculation of Day-Ahead Locational Marginal Prices.

III.2.3 Determination of System Conditions Using the State Estimator.

Power system operations, including, but not limited to, the determination of the least costly means of serving load and system and zonal Real-Time Operating Reserve requirements, depend upon the availability of a complete and consistent representation of generator outputs, loads, and power flows on the network. In calculating Day-Ahead Prices, the ISO shall base the system conditions on the expected transmission system configuration and the set of offers and bids submitted by Market Participants. In

calculating Real-Time Locational Marginal Prices and Real-Time Reserve Clearing Prices, the ISO shall obtain a complete and consistent description of conditions on the electric network in the New England Control Area by using the power flow solution produced by the State Estimator for the pricing interval, which is also used by the ISO for other functions within power system operations. The State Estimator is a standard industry tool that produces a power flow model based on available Real-Time metering information, information regarding the current status of lines, generators, transformers, and other equipment, bus load distribution factors, and a representation of the electric network, to provide a complete description of system conditions, including conditions at Nodes and External Nodes for which Real-Time information is unavailable. In calculating Real-Time Locational Marginal Prices and Real-Time Reserve Clearing Prices, the ISO shall obtain a State Estimator solution every five minutes, which shall provide the megawatt output of generators and the loads at Locations in the New England Control Area, transmission line losses, penalty factors, and actual flows or loadings on constrained transmission facilities. External Transactions between the New England Control Area and other Control Areas shall be included in the Real-Time Locational Marginal Price calculation on the basis of the Real-Time transaction schedules implemented by the ISO's dispatcher.

III.2.4 Adjustment for Rapid Response Pricing Assets.

For any Real-Time pricing interval during which a Rapid Response Pricing Asset is committed by the ISO, is in a dispatchable mode, and is not Self-Scheduled, the energy offer of that Rapid Response Pricing Asset shall be adjusted as described in this Section III.2.4 for purposes of the price calculations described in Section III.2.5 and Section III.2.7A. For purposes of the adjustment described in this Section III.2.4, if no Start-Up Fee, No-Load Fee, or Interruption Cost is specified in the submitted Offer Data, a value of zero shall be used; if no Minimum Run Time or Minimum Reduction Time is specified in the submitted Offer Data, or if the submitted Minimum Run Time or Minimum Reduction Time is less than 15 minutes, a duration of 15 minutes shall be used; and the energy offer after adjustment shall not exceed $2,000/MWh.

(a) If the Rapid Response Pricing Asset is a Fast Start Generator or a Flexible DNE Dispatchable Generator, its Economic Minimum Limit shall be set to zero; if the Rapid Response Pricing Asset is a Binary Storage DARD, its Minimum Consumption Limit shall be set to zero; if the Rapid Response Pricing Asset is a Fast Start Demand Response Resource, its Minimum Reduction shall be set to zero.

(b) If the Rapid Response Pricing Asset is a Fast Start Generator or a Flexible DNE Dispatchable Generator that has not satisfied its Minimum Run Time, its energy offer shall be increased by: (i) the

Start-Up Fee divided by the product of the Economic Maximum Limit and the Minimum Run Time; and (ii) the No-Load Fee divided by the Economic Maximum Limit.

(c) If the Rapid Response Pricing Asset is a Fast Start Generator or a Flexible DNE Dispatchable Generator that has satisfied its Minimum Run Time, its energy offer shall be increased by the No-Load Fee divided by the Economic Maximum Limit.

(d) If the Rapid Response Pricing Asset is a Fast Start Demand Response Resource that has not satisfied its Minimum Reduction Time, its energy offer shall be increased by the Interruption Cost divided by the product of the Maximum Reduction and the Minimum Reduction Time.

(e) If the Rapid Response Pricing Asset is a Fast Start Demand Response Resource that has satisfied its Minimum Reduction Time, its energy offer shall not be increased.

III.2.5 Calculation of Nodal Real-Time Prices.

(a) The ISO shall determine the least costly means of obtaining energy to serve the next increment of load at each Node internal to the New England Control Area represented in the State Estimator and each External Node Location between the New England Control Area and an adjacent Control Area, based on the system conditions described by the power flow solution produced by the State Estimator for the pricing interval. This calculation shall be made by applying an optimization method to minimize energy cost, given actual system conditions, a set of energy offers and bids (adjusted as described in Section III.2.4), and any binding transmission and Operating Reserve constraints that may exist. In performing this calculation, the ISO shall calculate the cost of serving an increment of load at each Node and External Node from all available Generator Assets (excluding Settlement Only Resources), Demand Response Resources, External Transaction purchases submitted under Section III.1.10.7 and Dispatchable Asset Related Demands with an eligible energy offer as the sum of: (1) the price at which the Market Participant has offered to supply or consume an additional increment of energy from the Resource; (2) the effect on Congestion Costs (whether positive or negative) associated with increasing the output of the Resource or reducing consumption of the Resource, based on the effect of increased output from that Resource or reduced consumption from that Resource on transmission line loadings; and (3) the effect on Congestion Costs (whether positive or negative) associated with increasing the Operating Reserve requirement, based on the effect of Resource re-dispatch on transmission line loadings; (4) the effect on Congestion Costs (whether positive or negative) associated with a deficiency in Operating Reserve, based on the effect of the Reserve Constraint Penalty Factors described under Section III.2.7A(c); and (5) the

effect on transmission losses caused by the increment of load, generation and demand reduction. The energy offer or offers and energy bid or bids that can jointly serve an increment of load and an increment of Operating Reserve requirement at a Location at the lowest cost, calculated in this manner, shall determine the Real-Time Price at that Node or External Node. For an external interface for which the enhanced scheduling procedures in Section III.1.10.7.A are implemented, the Real-Time Price at the External Node shall be further adjusted to include the effect on Congestion Costs (whether positive or negative) associated with a binding constraint limiting the external interface schedule, as determined when the interface is scheduled.

(b) During the Operating Day, the calculation set forth in this Section III.2.5 shall be performed for every five-minute interval, using the ISO's Locational Marginal Price program, producing a set of nodal Real-Time Prices based on system conditions during the pricing interval. The prices produced at five-minute intervals during an hour will be integrated to determine the nodal Real-Time Prices for that hour.

(c) For any interval during any hour in the Operating Day that the ISO has declared a Minimum Generation Emergency, the affected nodal Real-Time Prices calculated under this Section III.2.5 shall be set equal to the Energy Offer Floor for all Nodes within the New England Control Area and all External Nodes.

III.2.6 Calculation of Day-Ahead Prices.

III.2.6.1 Calculation of Day-Ahead Locational Marginal Prices.

(a) For the Day-Ahead Energy Market, Day-Ahead Locational Marginal Prices shall be determined on the basis of the least-cost, security-constrained unit commitment and dispatch, model flows and system conditions resulting from the load specifications submitted by Market Participants, Supply Offers, Demand Reduction Offers and Demand Bids for Resources, Increment Offers, Decrement Bids, External Transactions, and, commencing on June 1, 2024, the Forecast Energy Requirement Demand Quantity, Day-Ahead Ancillary Service demand quantities, and Energy Call Option Offers submitted to the ISO and scheduled in the Day-Ahead Energy Market.

Such prices shall be determined in accordance with the provisions of this Section applicable to the Day-Ahead Energy Market and shall be the basis for the settlement of purchases and sales of energy, costs for losses and Congestion Costs resulting from the Day-Ahead Energy Market. This calculation shall be made for each hour in the Day-Ahead Energy Market by applying an optimization method to minimize

energy and, commencing on June 1, 2024, ancillary services cost, given scheduled system conditions, scheduled transmission outages, and any transmission limitations that may exist. In performing this calculation, the ISO shall calculate the cost of serving an increment of load at each Node and External Node from each Resource associated with an eligible energy offer, energy bid, or Energy Call Option Offer as the sum of: (1) the price at which the Market Participant has offered to supply an additional increment of energy from the Resource or reduce consumption from the Resource and, commencing on June 1, 2024, the effect on ancillary service costs associated with increasing the output of the Resource or reducing consumption of the Resource; (2) the effect on transmission Congestion Costs (whether positive or negative) associated with increasing the output of the Resource or reducing consumption of the Resource, based on the effect of increased output from that Resource or reduced consumption from a Resource on transmission line loadings; and (3) the effect on transmission losses caused by the increment of load and supply. The energy offer or offers, Energy Call Option Offer or offers, and energy bid or bids that can serve an increment of load at a Node or External Node at the lowest cost, calculated in this manner, shall determine the Day-Ahead Locational Marginal Price at that Node.

For External Nodes for which the enhanced scheduling procedures in Section III.1.10.7.A are implemented, the clearing process specified in the previous two paragraphs shall apply. For all other External Nodes, the following process shall apply: in addition to determining the quantity cleared via the application of transmission constraints (i.e., limits on the flow over a line or set of lines), the quantity cleared is limited via the application of a nodal constraint (i.e., a limit on the total net injections at a Node) that restricts the net amount of cleared transactions to the transfer capability of the external interface. Clearing prices at all Nodes will reflect the marginal cost of serving the next increment of load at that Node while reflecting transmission constraints. A binding nodal constraint will result in interface limits being followed, but will not directly affect the congestion component of an LMP at an External Node.

(b) Energy deficient conditions. If the sum of Day-Ahead fixed Demand Bids and fixed External Transaction sales cannot be satisfied with the sum of all scheduled External Transaction purchases, cleared Increment Offers, and available supply at the Generator Asset’s Economic Maximum Limit and demand reduction at the Demand Response Resource’s Maximum Reduction, the technical software issues an Emergency Condition warning message due to a shortage of economic supply in the Day-Ahead Energy Market. The following steps shall then be performed to achieve power balance:

(i) All fixed External Transaction sales are considered to be dispatchable at the External Transaction Cap;

(ii) Reduce any remaining price-sensitive Demand Bids (including External Transaction sales) and Decrement Bids from lowest price to highest price to zero MW until power balance is achieved (there may be some price sensitive bids that are higher priced than the highest Supply Offer, Demand Reduction Offer, or Increment Offer price cleared). Set LMP values equal to the highest price-sensitive Demand Bid or Decrement Bid that was cut in this step. If no price-sensitive Demand Bid or Decrement Bid was reduced in this step, the LMP values are set equal to highest offer price of all on-line Generator Assets, dispatched Demand Response Resources, Increment Offers or External Transaction purchases; and

(iii) If power balance is not achieved after step (ii), reduce all remaining fixed Demand Bids proportionately (by ratio of load MW) until balance is achieved. Set LMP values equal to the highest offer price of all on-line Generator Assets (excluding Settlement Only Resources), dispatched Demand Response Resources, Increment Offers or External Transaction purchases or the price from step (ii), whichever is higher.

(c) Excess energy conditions. If the sum of Day-Ahead cleared Demand Bids, Decrement Bids and External Transaction sales is less than the total system wide supply (including fixed External Transaction purchases) with all possible Generator Assets off line and with all remaining Generator Assets at their Economic Minimum Limit, the technical software issues a Minimum Generation Emergency warning message due to an excess of economic supply in the Day-Ahead Energy Market. The following steps shall then be performed to achieve power balance:

(i) All fixed External Transaction purchases are considered to be dispatchable at the Energy Offer Floor and reduced pro-rata, as applicable, until power balance is reached;

(ii) If power balance is not reached in step (i), reduce all committed Generator Assets down proportionately by ratio of Economic Minimum Limits, but not below Emergency Minimum Limits. If power balance is achieved prior to reaching Emergency Minimum Limits, set LMP values equal to the lowest offer price of all on-line Generator Assets (excluding Settlement Only Resources); and

(iii) If power balance not achieved in step (ii), set LMP values to Energy Offer Floor and reduce all Generator Assets generation below Emergency Minimum Limits proportionately (by ratio of Emergency Minimum Limits) to achieve power balance.

III.2.6.2 Calculation of Additional Day-Ahead Prices.

(a) Commencing on June 1, 2024, the ISO shall calculate hourly Day-Ahead Prices for additional requirements in the Day-Ahead Energy Market as described in this Section III.2.6.2(a).

(i) The clearing price for Day-Ahead Four-Hour Reserve shall be the incremental cost, as measured by the change in the Day-Ahead Energy Market's security-constrained economic dispatch objective value, to satisfy the next increment of the Day-Ahead Total Four-Hour Reserve Demand Quantity.

(ii) The clearing price for Day-Ahead Ninety-Minute Reserve shall be the sum of (a) the incremental cost, as measured by the change in the Day-Ahead Energy Market's security-constrained economic dispatch objective value, to satisfy the next increment of the Day-Ahead Total Ninety-Minute Reserve Demand Quantity, and (b) the clearing price for Day-Ahead Four-Hour Reserve.

(iii) The clearing price for Day-Ahead Thirty-Minute Operating Reserve shall be the sum of (a) the incremental cost, as measured by the change in the Day-Ahead Energy Market's security-constrained economic dispatch objective value, to satisfy the next increment of the Day-Ahead Total Thirty-Minute Operating Reserve Demand Quantity, and (b) the clearing price for Day-Ahead Ninety-Minute Reserve.

(iv) The clearing price for Day-Ahead Ten-Minute Non-Spinning Reserve shall be the sum of (a) the incremental cost, as measured by the change in the Day-Ahead Energy Market's security-constrained economic dispatch objective value, to satisfy the next increment of the Day-Ahead Total Ten-Minute Reserve Demand Quantity, and (b) the clearing price for Day-Ahead Thirty-Minute Operating Reserve.

(v) The clearing price for Day-Ahead Ten-Minute Spinning Reserve shall be the sum of (a) the incremental cost, as measured by the change in the Day-Ahead Energy Market's security-constrained economic dispatch objective value, to satisfy the next increment of the Day-Ahead

Ten-Minute Spinning Reserve Demand Quantity, and (b) the clearing price for Day-Ahead Ten-Minute Non-Spinning Reserve.

(vi) The clearing price for Day-Ahead Energy Imbalance Reserve shall be the Forecast Energy Requirement Price.

(vii) The Forecast Energy Requirement Price shall be the marginal cost, as measured by the change in the Day-Ahead Energy Market's security-constrained economic dispatch objective value, to satisfy the next increment of the Forecast Energy Requirement Demand Quantity.

(b) **Reserve Constraint Penalty Factors.** The Day-Ahead Energy Market scheduling pursuant to Section III.1.10.8(a)(ii), and the Day-Ahead Prices specified in Section III.2.6, shall respect the applicable Reserve Constraint Penalty Factors specified below:

(i) The Reserve Constraint Penalty Factor applicable to the Day-Ahead Ten-Minute Spinning Reserve Demand Quantity shall be equal to the Real-Time Ten-Minute Spinning Reserve Requirement Reserve Constraint Penalty Factor specified in Section III.2.7A.

(ii) The Reserve Constraint Penalty Factor applicable to the Day-Ahead Total Ten-Minute Reserve Demand Quantity shall be equal to the Real-Time Ten-Minute Reserve Requirement Reserve Constraint Penalty Factor specified in Section III.2.7A.

(iii) The Reserve Constraint Penalty Factor applicable to the Day-Ahead Total Thirty-Minute Operating Reserve Demand Quantity shall be equal to the Real-Time Minimum Total Reserve Requirement Reserve Constraint Penalty Factor specified in Section III.2.7A.

(iv) The Reserve Constraint Penalty Factor applicable to the Day-Ahead Total Ninety-Minute Reserve Demand Quantity shall be equal to $250/MWh.

(v) The Reserve Constraint Penalty Factor applicable to the Day-Ahead Total Four-Hour Reserve Demand Quantity shall be equal to $100/MWh.

(vi) The Reserve Constraint Penalty Factor applicable to the Forecast Energy Requirement Demand Quantity shall be set at 101% of the sum of the Reserve Constraint Penalty Factors in Sections III.2.6.2(b)(i)-(v).

III.2.7 Reliability Regions, Load Zones, Reserve Zones, Zonal Prices and External Nodes.

(a) The ISO shall calculate Zonal Prices for each Load Zone and DRR Aggregation Zone for both the Day-Ahead Energy Market and Real-Time Energy Markets using a load-weighted average of the Locational Marginal Prices for the Nodes within that Load Zone or DRR Aggregation Zone. The load weights used in calculating the Day-Ahead Zonal Prices for the Load Zone and DRR Aggregation Zone shall be determined in accordance with applicable Market Rule 1 provisions and shall be based on historical load usage patterns. The load weights do not reflect Demand Bids or Decrement Bids that settle at the Node level in the Day-Ahead Energy Market. The ISO shall determine, in accordance with applicable ISO New England Manuals, the load weights used in Real-Time based on the actual Real-Time load distribution as calculated by the State Estimator, and shall exclude any Asset Related Demand from the load weights used to calculate the applicable Real-Time Zonal Prices.

(b) Each Load Zone shall initially be approximately coterminous with a Reliability Region.

(c) Reserve Zones shall be established by the ISO which represent areas within the New England Transmission System that require local 30 minute contingency response as part of normal system operations in order to satisfy local 2nd contingency response reliability criteria.

(d) The remaining area within the New England Transmission System that is not included within the Reserve Zones established under Section III.2.7(c) is Rest of System.

(e) Each Reserve Zone shall be completely contained within a Load Zone or shall be defined as a subset of the Nodes contained within a Load Zone.

(f) The ISO shall calculate Forward Reserve Clearing Prices and Real-Time Reserve Clearing Prices for each Reserve Zone.

(g) After consulting with the Market Participants, the ISO may reconfigure Reliability Regions, Load Zones, Dispatch Zones, and Reserve Zones and add or subtract Reliability Regions, Load Zones, Dispatch

Zones, and Reserve Zones as necessary over time to reflect changes to the grid, patterns of usage, changes in local TMOR contingency response requirements and intrazonal Congestion. The ISO shall file any such changes with the Commission.

(h) In the event the ISO makes changes to a Reliability Region or Load Zone or adds or subtracts Reliability Regions and Load Zones, for settlement purposes and to the extent practicable, Load Assets that are physically located in one Reliability Region and electrically located within another Reliability Region shall be located within the Reliability Region to which they are electrically located.

(i) External Nodes are the nodes at which External Transactions settle. As appropriate and after consulting with Market Participants, the ISO will establish and re-configure External Nodes taking into consideration appropriate factors, which may include: tie line operational matters, FTR modeling and auction assumptions, market power issues associated with external contractual arrangements, impacts on Locational Marginal Prices, and inter-regional trading impacts.

(j) On or about the 20th calendar day of each month, the ISO shall publish the Real-Time nodal load weights (expressed in MW) used to calculate the load-weighted Real-Time Zonal Prices for the preceding month. Nodal load weights will be published for all nodes used in the calculations except for those nodes identified by customers as nodes for which publication would provide individual customer usage data. Any individual customer whose usage data would be revealed by publication of load weight information associated with a specific Node must submit a written request to the ISO to omit the applicable Node from the publication requirement. The request must identify the affected Node and, to the best of the customer’s knowledge, the number of customers taking service at the affected Node and the estimated percentage of the total annual load (MWh) at the affected Node period that is attributable to the customer. The information contained in the request must be certified in writing by an officer of the customer’s company (if applicable), by an affidavit signed by a person having knowledge of the applicable facts, or by representation of counsel for the customer. The ISO will grant a customer request if it determines based on the information provided that no more than two customers are taking service at the affected Node or that the percentage of the customer’s annual load (MWh) at the affected Node is greater than 75 percent of the total load (MWh) at the affected Node. If a customer request is granted and that customer request is the only such customer request within a Load Zone, then the ISO shall randomly select one other Node and not disclose hourly load information for the randomly selected Node unless and until another customer request within the Load Zone is granted. A request to suspend publication for a month must be received by the ISO on or before the 10th calendar day of the following month in order to be

effective for that month. Upon receipt of a request, the ISO will suspend publication of the load weight data for the specified Node. The ISO may, from time to time, require customer confirmation that continued omission from publication of load weight data for a particular Node is required in order to avoid disclosure of individual customer usage data. If customer confirmation is not received within a reasonable period not to exceed 30 days, the ISO may publish load weight data for the applicable Node.

III.2.7A Calculation of Real-Time Reserve Clearing Prices.

(a) The ISO shall obtain Operating Reserve in Real-Time to serve Operating Reserve requirements for the system and each Reserve Zone on a jointly optimized basis with the calculation of nodal Real-Time Prices specified under Section III.2.5, based on the system conditions described by the power flow solution produced by the State Estimator program for the pricing interval. This calculation shall be made by applying an optimization method to maximize social surplus, given actual system conditions, a set of energy offers and bids, and any binding transmission constraints, including binding transmission interface constraints associated with meeting Operating Reserve requirements, and binding Operating Reserve constraints that may exist. In performing this calculation, the ISO shall calculate, on a jointly optimized basis with serving an increment of load at each Node and External Node, the cost of serving an increment of Operating Reserve requirement for the system and each Reserve Zone from all available Generator Assets (excluding Settlement Only Resources), Demand Response Resources and Dispatchable Asset Related Demands with an eligible energy offer or bid. Real-Time Reserve Clearing Prices will be equal to zero unless system re-dispatch is required in order to meet the system and zonal Operating Reserve requirements or there is a deficiency in available Operating Reserve, in which case Real-Time Reserve Clearing Prices shall be set as described in Section III.2.7A(b) and Section III.2.7A(c).

(b) If system re-dispatch is required to maintain sufficient levels of Operating Reserve, the applicable Real-Time Reserve Clearing Price is equal to the highest unit-specific Real-Time Reserve Opportunity Cost associated with all Generator Assets, Demand Response Resources and Dispatchable Asset Related Demands that were re-dispatched to meet the applicable Operating Reserve requirement. The Real-Time Reserve Opportunity Cost of a Resource shall be equal to the difference between (i) the Real-Time Energy LMP at the Location for the Resource and (ii) the offer price associated with the re-dispatch of the Resource necessary to create the additional Operating Reserve.

(c) If there is insufficient Operating Reserve available to meet the Operating Reserve requirements for the system and/or any Reserve Zone or sufficient Operating Reserve is not available at a redispatch

cost equal to or less than that specified by the Reserve Constraint Penalty Factors, the applicable Real-Time Reserve Clearing Prices shall be set based upon the following Reserve Constraint Penalty Factors:

Real-Time Requirement	**Reserve Constraint Penalty Factor**
Zonal Reserve Requirement (combined amount of TMSR, TMNSR, and TMOR required for a Reserve Zone)	$250/MWh
Minimum Total Reserve Requirement (does not include Replacement Reserve) (combined amount of TMSR, TMNSR, and TMOR required system-wide)	$1000/MWh
Total Reserve Requirement (includes Replacement Reserve) (combined amount of TMSR, TMNSR, and TMOR required system-wide)	$250/MWh
Ten-Minute Reserve Requirement (combined amount of TMSR and TMNSR required system-wide)	$1500/MWh
Ten-Minute Spinning Reserve Requirement (amount of TMSR required system-wide)	$50/MWh

The Reserve Constraint Penalty Factors shall be applied in a manner that is consistent with the price cascading described in Section III.2.7A(d).

(d) Real-Time Reserve designations and Real-Time Reserve Clearing Prices shall be calculated in such a manner to ensure that excess Real-Time Operating Reserve capability will cascade down for use in meeting any remaining Real-Time Operating Reserve requirements from TMSR to TMNSR to TMOR and that the pricing of Real-Time Operating Reserve shall cascade up from TMOR to TMNSR to TMSR.

(e) During the Operating Day, the calculation set forth in this Section III.2.7A shall be performed for every five-minute interval, using the ISO's Unit Dispatch System and Locational Marginal Price program, producing a set of zonal Real-Time Reserve Clearing Prices based on system conditions for the pricing interval. The prices produced at five-minute intervals during an hour will be integrated to determine the Real-Time Reserve Clearing Prices for the system and/or each Reserve Zone for that hour.

III.2.8 Hubs and Hub Prices.

(a) On behalf of the Market Participants, the ISO shall maintain and facilitate the use of a Hub or Hubs for the Day-Ahead Energy Market and Real-Time Energy Market, comprised of a set of Nodes

within the New England Control Area, which Nodes shall be identified by the ISO on its internet website. The ISO has used the following criteria to establish an initial Hub and shall use the same criteria to establish any additional Hubs:

(i) Each Hub shall contain a sufficient number of Nodes to try to ensure that a Hub Price can be calculated for that Hub at all times;

(ii) Each Hub shall contain a sufficient number of Nodes to ensure that the unavailability of, or an adjacent line outage to, any one Node or set of Nodes would have only a minor impact on the Hub Price;

(iii) Each Hub shall consist of Nodes with a relatively high rate of service availability;

(iv) Each Hub shall consist of Nodes among which transmission service is relatively unconstrained; and

(v) No Hub shall consist of a set of Nodes for which directly connected load and/or generation at that set of Nodes is dominated by any one entity or its Affiliates.

(b) The ISO shall calculate and publish Hub Prices for both the Day-Ahead and Real-Time Energy Markets based upon the arithmetic average of the Locational Marginal Prices of the nodes that comprise the Hub.

III.2.9A Final Real Time Prices, Real-Time Reserve Clearing and Regulation Clearing Prices.

(a) The ISO normally will post provisional Real-Time Prices, Real-Time Reserve Clearing Prices and Regulation clearing prices in Real-Time or soon thereafter. The ISO shall post the final Real-Time Prices, final Real-Time Reserve Clearing Prices and final Regulation clearing prices as soon as practicable following the Operating Day, in accordance with the timeframes specified in the ISO New England Manuals, except that the posting of such final Real-Time Prices, final Real-Time Reserve Clearing Prices and final Regulation clearing prices by the ISO shall not exceed five business days from the applicable Operating Day. If the ISO is not able to calculate Real-Time Prices, Real-Time Reserve Clearing Prices or Regulation clearing prices normally due to human error, hardware, software, or telecommunication problems that cannot be remedied in a timely manner, the ISO will calculate Real-

Time Prices, Real-Time Reserve Clearing Prices or Regulation clearing prices as soon as practicable using the best data available; provided, however, in the event that the ISO is unable to calculate and post final Real-Time Prices, Real-Time Reserve Clearing Prices or Regulation clearing prices due to exigent circumstances not contemplated in this market rule, the ISO shall make an emergency filing with the Commission within five business days from the applicable Operating Day detailing the exigent circumstance, which will not allow the final clearing prices to be calculated and posted, along with a proposed resolution including a timeline to post final clearing prices.

(b) The permissibility of correction of errors in Real-Time Prices, Real-Time Reserve Clearing Prices or Regulation clearing prices for an Operating Day due to database, software or similar errors of the ISO or its systems, and the timeframes and procedures for permitted corrections, are addressed solely in this Section III.2.9A and not in those sections of Market Rule 1 relating to settlement and billing processes.

III.2.9B Final Day-Ahead Energy Market Results

(a) Day-Ahead Energy Market results are final when published except as provided in this subsection. If the ISO determines based on reasonable belief that there may be one or more errors in the Day-Ahead Energy Market results for an Operating Day or if no Day-Ahead Energy Market results are available due to human error, database, software or similar errors of the ISO or its systems, the ISO shall post on the ISO website prior to 12:01 a.m. of the applicable Operating Day, a notice that the results are provisional and subject to correction or unavailable for initial publishing. Any Day-Ahead Energy Market results for which no notice is posted shall be final and not subject to correction or other adjustment, and shall be used for purposes of settlement. The ISO shall confirm within three business days of the close of the applicable Operating Day whether there was an error in any provisional Day-Ahead Energy Market results and shall post a notice stating its findings.

(b) The ISO will publish corrected Day-Ahead Energy Market results within three business days of the close of the applicable Operating Day or the results of the Day-Ahead Energy Market for the Operating Day will stand; provided, however, in the event that the ISO is unable to calculate and post final Day-Ahead Energy Market Results due to exigent circumstances not contemplated in this market rule, the ISO shall make an emergency filing with the Commission within five business days from the applicable Operating Day detailing the exigent circumstance, which will not allow the final prices to be calculated and posted, along with a proposed resolution including a timeline to post final prices. The ISO shall also publish a statement describing the nature of the error and the method used to correct the results.

(c) If the ISO determines in accordance with subsection (a) that there are one or more errors in the Day-Ahead Energy Market results for an Operating Day, the ISO shall calculate corrected Day-Ahead Energy Market results by determining and substituting for the initial results, final results that reasonably reflect how the results would have been calculated but for the errors. To the extent that it is necessary, reasonable and practicable to do so, the ISO may specify an allocation of any costs that are not otherwise allocable under applicable provisions of Market Rule 1. The ISO shall use the corrected results for purposes of settlement.

(d) For every change in the Day-Ahead Energy Market results made pursuant to Section III.2.9B, the ISO will prepare and submit, as soon as practicable, an informational report to the Commission describing the nature of any errors, the precise remedy administered, the method of determining corrected prices and allocating any costs, and any remedial actions that will be taken to avoid similar errors in the future.

(e) The permissibility of correction of errors in Day-Ahead Energy Market results, and the timeframes and procedures for permitted corrections, are addressed solely in this Section III.2.9B and not in those sections of Market Rule 1 relating to settlement and billing processes.

III.3 Accounting And Billing

III.3.1 Introduction.

This Section III.3 sets forth the accounting and billing principles and procedures for the purchase and sale of services in the New England Markets and for the operation of the New England Control Area.

If a dollar-per-MW-hour value is applied in a calculation where the interval of the value produced in that calculation is less than an hour, then for purposes of that calculation the dollar-per-MW-hour value is divided by the number of intervals in the hour.

III.3.2 Market Participants.

III.3.2.1 ISO Energy Market.

For purposes of establishing the following positions, unless otherwise expressly stated, the settlement interval for the Real-Time Energy Market is five minutes and the settlement interval for the Day-Ahead Energy Market is hourly. The Real-Time Energy Market settlement is determined using the Metered Quantity For Settlement calculated in accordance with Section III.3.2.1.1.

(a)(1) **Day-Ahead Energy Market Energy Obligations** – For each Market Participant for each settlement interval, the ISO will determine a Day-Ahead Energy Market position representing that Market Participant's net purchases from or sales to the Day-Ahead Energy Market as follows:

(i) **Day-Ahead Load Obligation** – Each Market Participant shall have for each settlement interval a Day-Ahead Load Obligation for energy at each Location equal to the MWhs of its Demand Bids, Decrement Bids and External Transaction sales accepted by the ISO in the Day-Ahead Energy Market at that Location and such Day-Ahead Load Obligation shall have a negative value.

(ii) **Day-Ahead Generation Obligation** – Each Market Participant shall have for each settlement interval a Day-Ahead Generation Obligation for energy at each Location equal to the MWhs of its Supply Offers, Increment Offers and External Transaction purchases accepted by the ISO in the Day-Ahead Energy Market at that Location and such Day-Ahead Generation Obligation shall have a positive value.

(iii) **Day-Ahead Demand Reduction Obligation** – Each Market Participant shall have for each settlement interval a Day-Ahead Demand Reduction Obligation at each Location equal to the MWhs of its Demand Reduction Offers accepted by the ISO in the Day-Ahead Energy Market at that Location, increased by average avoided peak distribution losses. Day-Ahead Demand Reduction Obligations shall have a positive value.

(iv) **Day-Ahead Adjusted Load Obligation** – Each Market Participant shall have for each settlement interval a Day-Ahead Adjusted Load Obligation at each Location equal to the Day-Ahead Load Obligation adjusted by any applicable Day-Ahead internal bilateral transactions at that Location.

(v) **Day-Ahead Locational Adjusted Net Interchange** – Each Market Participant shall have for each settlement interval a Day-Ahead Locational Adjusted Net Interchange at each Location equal to the Day-Ahead Adjusted Load Obligation plus the Day-Ahead Generation Obligation plus the Day-Ahead Demand Reduction Obligation at that Location.

(a)(2) **Day-Ahead Energy Market Ancillary Services Obligations** – Commencing on June 1, 2024, each Market Participant with an Energy Call Option Offer that is accepted by the ISO in the Day-Ahead Energy Market shall have for each settlement interval a Day-Ahead Ancillary Services obligation as follows:

(i) **Day-Ahead Ten-Minute Spinning Reserve Obligation** – A Market Participant with an accepted Energy Call Option Offer quantity that contributes to satisfying the Day-Ahead Ten-Minute Spinning Reserve Demand Quantity shall receive a Day-Ahead Ten-Minute Spinning Reserve Obligation.

(ii) **Day-Ahead Ten-Minute Non-Spinning Reserve Obligation** – A Market Participant with an accepted Energy Call Option Offer quantity that contributes to satisfying the Day-Ahead Total Ten-Minute Reserve Demand Quantity, and that same Energy Call Option Offer quantity does not receive a Day-Ahead Ten-Minute Spinning Reserve Obligation, shall receive a Day-Ahead Ten-Minute Non-Spinning Reserve Obligation.

(iii) **Day-Ahead Thirty-Minute Operating Reserve Obligation** – A Market Participant with an accepted Energy Call Option Offer quantity that contributes to satisfying the Day-Ahead Total

Thirty-Minute Operating Reserve Demand Quantity, and that same Energy Call Option Offer quantity does not receive either a Day-Ahead Ten-Minute Spinning Reserve Obligation or a Day-Ahead Ten-Minute Non-Spinning Reserve Obligation, shall receive a Day-Ahead Thirty-Minute Operating Reserve Obligation.

(iv) **Day-Ahead Ninety-Minute Reserve Obligation** – A Market Participant with an accepted Energy Call Option Offer quantity that contributes to satisfying the Day-Ahead Total Ninety-Minute Reserve Demand Quantity, and that same Energy Call Option Offer quantity does not receive a Day-Ahead Ten-Minute Spinning Reserve Obligation, a Day-Ahead Ten-Minute Non-Spinning Reserve Obligation, or a Day-Ahead Thirty-Minute Operating Reserve Obligation, shall receive a Day-Ahead Ninety-Minute Reserve Obligation.

(v) **Day-Ahead Four-Hour Reserve Obligation** – A Market Participant with an accepted Energy Call Option Offer quantity that contributes to satisfying the Day-Ahead Total Four-Hour Reserve Demand Quantity, and that same Energy Call Option Offer quantity does not receive a Day-Ahead Ten-Minute Spinning Reserve Obligation, a Day-Ahead Ten-Minute Non-Spinning Reserve Obligation, a Day-Ahead Thirty-Minute Operating Reserve Obligation, or a Day-Ahead Ninety-Minute Reserve Obligation, shall receive a Day-Ahead Four-Hour Reserve Obligation.

(vi) **Day-Ahead Energy Imbalance Reserve Obligation** – A Market Participant with an accepted Energy Call Option Offer quantity that contributes to satisfying the Forecast Energy Requirement Demand Quantity shall receive a Day-Ahead Energy Imbalance Reserve Obligation.

(b) **Real-Time Energy Market Obligations Excluding Demand Response Resource Contributions** – For each Market Participant for each settlement interval, the ISO will determine a Real-Time Energy Market position. For purposes of these calculations, if the settlement interval is less than one hour, any internal bilateral transaction shall be equally apportioned over the settlement intervals within the hour. To accomplish this, the ISO will perform calculations to determine the following:

(i) **Real-Time Load Obligation** – Each Market Participant shall have for each settlement interval a Real-Time Load Obligation for energy at each Location equal to the MWhs of load, where such MWhs of load shall include External Transaction sales and shall have a negative value, at that Location, adjusted for unmetered load and any applicable internal bilateral transactions which transfer Real-Time load obligations.

(ii) **Real-Time Generation Obligation** – Each Market Participant shall have for each settlement interval a Real-Time Generation Obligation for energy at each Location. The Real-Time Generation Obligation shall equal the MWhs of energy, where such MWhs of energy shall have positive value, provided by Generator Assets and External Transaction purchases at that Location.

(iii) **Real-Time Adjusted Load Obligation** – Each Market Participant shall have for each settlement interval a Real-Time Adjusted Load Obligation at each Location equal to the Real-Time Load Obligation adjusted by any applicable energy related internal Real-Time bilateral transactions at that Location.

(iv) **Real-Time Locational Adjusted Net Interchange –** Each Market Participant shall have for each settlement interval a Real-Time Locational Adjusted Net Interchange at each Location equal to the Real-Time Adjusted Load Obligation plus the Real-Time Generation Obligation at that Location.

(v) **Marginal Loss Revenue Load Obligation –** Each Market Participant shall have for each settlement interval a Marginal Loss Revenue Load Obligation at each Location equal to the Real-Time Load Obligation adjusted by any energy related internal Real-Time bilateral transactions at that Location that the parties to those bilateral transactions have elected to include in their Marginal Loss Revenue Load Obligation for the purpose of allocating Day-Ahead Loss Revenue and Real-Time Loss Revenue. Contributions from Coordinated External Transactions shall be excluded from the Real-Time Load Obligation for purposes of determining Marginal Loss Revenue Load Obligation.

(c) **Real-Time Energy Market Obligations For Demand Response Resources**

Real-Time Demand Reduction Obligation – Each Market Participant shall have for each settlement interval a Real-Time Demand Reduction Obligation at each Location equal to the MWhs of demand reduction provided by Demand Response Resources at that Location in response to non-zero Dispatch Instructions. The MWhs of demand reduction produced by a Demand Response Resource are equal to the sum of the demand reductions produced by its constituent Demand Response Assets calculated pursuant to Section III.8.4, where the demand reductions, other than MWhs associated with Net Supply, are increased by average avoided peak distribution losses.

(d) **<u>Real-Time Energy Market Deviations Excluding Demand Response Resource Contributions</u>** – For each Market Participant for each settlement interval, the ISO will determine the difference between the Real-Time Energy Market position (calculated in accordance with Section III.3.2.1(b)) and the Day-Ahead Energy Market position (calculated in accordance with Section III.3.2.1(a)(1)) representing that Market Participant's net purchases from or sales to the Real-Time Energy Market (excluding any such transactions involving Demand Response Resources). For purposes of this calculation, if the Real-Time settlement interval is less than one hour, the Day-Ahead position shall be equally apportioned over the settlement intervals within the hour. To accomplish this, the ISO will perform calculations to determine the following:

(i) **Real-Time Load Obligation Deviation** – Each Market Participant shall have for each settlement interval a Real-Time Load Obligation Deviation at each Location equal to the difference in MWhs between the Real-Time Load Obligation and the Day-Ahead Load Obligation.

(ii) **Real-Time Generation Obligation Deviation** – Each Market Participant shall have for each settlement interval a Real-Time Generation Obligation Deviation at each Location equal to the difference in MWhs between the Real-Time Generation Obligation and the Day-Ahead Generation Obligation.

(iii) **Real-Time Adjusted Load Obligation Deviation** – Each Market Participant shall have for each settlement interval a Real-Time Adjusted Load Obligation Deviation at each Location equal to the difference in MWhs between the Real-Time Adjusted Load Obligation and the Day-Ahead Adjusted Load Obligation.

(iv) **Real-Time Locational Adjusted Net Interchange Deviation** – Each Market Participant shall have for each settlement interval a Real-Time Locational Adjusted Net Interchange Deviation at each Location equal to the difference in MWhs between (1) the Real-Time Locational Adjusted Net Interchange and (2) the Day-Ahead Locational Adjusted Net Interchange minus the Day-Ahead Demand Reduction Obligation for that Location.

(e) **<u>Real-Time Energy Market Deviations For Demand Response Resources</u>**

Real-Time Demand Reduction Obligation Deviation – Each Market Participant shall have for each settlement interval a Real-Time Demand Reduction Obligation Deviation at each Location equal to the difference in MWhs between the Real-Time Demand Reduction Obligation (calculated in accordance with Section III.3.2.1(c)) and the Day-Ahead Demand Reduction Obligation (calculated in accordance with Section III.3.2.1(a)(1)). For purposes of this calculation, if the Real-Time settlement interval is less than one hour, the Day-Ahead position shall be equally apportioned over the settlement intervals within the hour.

(f) **Day-Ahead Energy Market Energy Charge/Credit** – For each Market Participant for each settlement interval, the ISO will determine Day-Ahead Energy Market monetary positions representing a charge or credit for its net purchases from or sales to the ISO Day-Ahead Energy Market. The Day-Ahead Energy Market Energy Charge/Credit shall be equal to the sum of its Location specific Day-Ahead Locational Adjusted Net Interchanges multiplied by the Energy Component of the associated Day-Ahead Locational Marginal Prices. The Day-Ahead Energy Market Congestion Charge/Credit shall be equal to the sum of its Location specific Day-Ahead Locational Adjusted Net Interchanges multiplied by the Congestion Component of the associated Day-Ahead Locational Marginal Prices. The Day-Ahead Energy Market Loss Charge/Credit shall be equal to the sum of its Location specific Day-Ahead Locational Adjusted Net Interchanges multiplied by the Loss Component of the associated Day-Ahead Locational Marginal Prices.

(g) **Real-Time Energy Market Charge/Credit Excluding Demand Response Resources –** For each Market Participant for each settlement interval, the ISO will determine Real-Time Energy Market monetary positions representing a charge or credit to the Market Participant for its net purchases from or sales to the Real-Time Energy Market (excluding any such transactions involving Demand Response Resources). The Real-Time Energy Market Deviation Energy Charge/Credit shall be equal to the sum of the Market Participant's Location specific Real-Time Locational Adjusted Net Interchange Deviations for that settlement interval multiplied by the Energy Component of the Real-Time Locational Marginal Prices. The Real-Time Energy Market Deviation Congestion Charge/Credit shall be equal to the sum of the Market Participant's Location specific Real-Time Locational Adjusted Net Interchange Deviations for that settlement interval multiplied by the Congestion Component of the associated Real-Time Locational Marginal Prices. The Real-Time Energy Market Deviation Loss Charge/Credit shall be equal to the sum of the Market Participant's Location specific Real-Time Locational Adjusted Net Interchange Deviations for that settlement interval multiplied by the Loss Component of the associated Real-Time Locational Marginal Prices.

(h) **<u>Real-Time Energy Market Charge/Credit For Demand Response Resources</u> –** For each Market Participant for each settlement interval, the ISO shall calculate a charge or credit to the Market Participant for its net purchases from or sales to the Real-Time Energy Market associated with Demand Response Resources. The charge or credit shall be equal to the sum of the Market Participant's Location-specific Real-Time Demand Reduction Obligation Deviations for that settlement interval multiplied by the Real-Time Locational Marginal Prices. Such charges and credits shall be allocated on an hourly basis to Market Participants based on their pro rata share of the sum of all Market Participants' Real-Time Load Obligation, excluding the Real-Time Load Obligation incurred at all External Nodes, and excluding Real-Time Load Obligation incurred by Storage DARDs.

(i) **<u>Day-Ahead and Real-Time Congestion Revenue</u>** – For each settlement interval, the ISO will determine the total revenues associated with transmission congestion on the New England Transmission System. To accomplish this, the ISO will perform calculations to determine the following. The Day-Ahead Congestion Revenue shall equal the sum of all Market Participants' Day-Ahead Energy Market Congestion Charge/Credits. The Real-Time Congestion Revenue shall equal the sum of all Market Participants' Real-Time Energy Market Deviation Congestion Charge/Credits.

(j) **<u>Day-Ahead Loss Revenue</u>** – For each settlement interval, the ISO will determine the excess or deficiency in loss revenue associated with the Day-Ahead Energy Market. The Day-Ahead Loss Revenue shall be equal to the sum of all Market Participants' Day-Ahead Energy Market Energy Charge/Credits and Day-Ahead Energy Market Loss Charge/Credits.

(k) **<u>Day-Ahead Loss Charges or Credits</u>** – For each settlement interval for each Market Participant, the ISO shall calculate a Day-Ahead payment or charge associated with the excess or deficiency in loss revenue (Section III.3.2.1(j)). The Day-Ahead Loss Charges or Credits shall be equal to the Day-Ahead Loss Revenue multiplied by the Market Participant's pro rata share of the sum of all Market Participants' Marginal Loss Revenue Load Obligations.

(l) **<u>Real-Time Loss Revenue</u>** – For each settlement interval, the ISO will determine the excess or deficiency in loss revenue associated with the Real-Time Energy Market. The Real-Time Loss Revenue shall be equal to the sum of all Market Participants' Real-Time Energy Market Deviation Energy Charge/Credit and Real-Time Energy Market Deviation Loss Charge/Credit plus Non-Market Participant Transmission Customer loss costs. The ISO will then adjust Real-Time Loss Revenue to account for

Inadvertent Energy Revenue, as calculated under Section III.3.2.1(o) and Emergency transactions as described under Section III.4.3(a).

(m) **Real-Time Loss Revenue Charges or Credits** – For each hour for each Market Participant, the ISO shall calculate a Real-Time payment or charge associated with the excess or deficiency in Real-Time Loss Revenue (Section III.3.2.1(l)). The Real-Time Loss Revenue Charges or Credits shall be equal to the Real-Time Loss Revenue multiplied by the Market Participant's pro rata share of the sum of all Market Participants' Marginal Loss Revenue Load Obligations.

(n) **Non-Market Participant Loss** – Non-Market Participant Transmission Customer loss costs shall be assessed for transmission use scheduled in the Real-Time Energy Market, calculated as the amount to be delivered in each settlement interval multiplied by the difference between the Loss Component of the Real-Time Price at the delivery point or New England Control Area boundary delivery interface and the Loss Component of the Real-Time Price at the source point or New England Control Area boundary source interface.

(o) **Inadvertent Energy Revenue** – For each External Node, for each settlement interval the ISO will calculate an excess or deficiency in Inadvertent Energy Revenue by multiplying the Inadvertent Interchange at the External Node by the associated Real-Time Locational Marginal Price. For each settlement interval, the total Inadvertent Energy Revenue for a settlement interval shall equal the sum of the Inadvertent Energy Revenue values for each External Node for that interval.

(p) **Inadvertent Energy Revenue Charges or Credits** – For each hour for each Market Participant, the ISO shall calculate a Real-Time payment or charge associated with the excess or deficiency in Inadvertent Energy Revenue (Section III.3.2.1(o)). The Inadvertent Energy Revenue Charges or Credits shall be equal to the Inadvertent Energy Revenue multiplied by the Market Participant's pro rata share of the sum of all Market Participants' Real-Time Load Obligations, Real-Time Generation Obligations, and Real-Time Demand Reduction Obligations over all Locations, measured as absolute values, excluding contributions to Real-Time Load Obligations and Real-Time Generation Obligations from Coordinated External Transactions.

(q)(1) **Day-Ahead Energy Market Ancillary Services Credit** – Commencing on June 1, 2024, each Market Participant with a Day-Ahead Ancillary Services obligation shall receive a credit as follows:

(i) **Day-Ahead Ten-Minute Spinning Reserve credit** – Each MWh of Day-Ahead Ten-Minute Spinning Reserve Obligation shall be credited the clearing price for Day-Ahead Ten-Minute Spinning Reserve calculated in accordance with Section III.2.6.2(a)(v).

(ii) **Day-Ahead Ten-Minute Non-Spinning Reserve credit** – Each MWh of Day-Ahead Ten-Minute Non-Spinning Reserve Obligation shall be credited the clearing price for Day-Ahead Ten-Minute Non-Spinning Reserve calculated in accordance with Section III.2.6.2(a)(iv).

(iii) **Day-Ahead Thirty-Minute Operating Reserve credit** – Each MWh of Day-Ahead Thirty-Minute Operating Reserve Obligation shall be credited the clearing price for Day-Ahead Thirty-Minute Operating Reserve calculated in accordance with Section III.2.6.2(a)(iii).

(iv) **Day-Ahead Ninety-Minute Reserve credit** – Each MWh of Day-Ahead Ninety-Minute Reserve Obligation shall be credited the clearing price for Day-Ahead Ninety-Minute Reserve calculated in accordance with Section III.2.6.2(a)(ii).

(v) **Day-Ahead Four-Hour Reserve credit** – Each MWh of Day-Ahead Four-Hour Reserve Obligation shall be credited the clearing price for Day-Ahead Four-Hour Reserve calculated in accordance with Section III.2.6.2(a)(i).

(vi) **Day-Ahead Energy Imbalance Reserve credit** – Each MWh of Day-Ahead EnergImbalance Reserve Obligation shall be credited the clearing price for Day-Ahead Energy Imbalance Reserve calculated in accordance with Section III.2.6.2(a)(vi).

(q)(2) **<u>Day-Ahead Energy Market Ancillary Services Close-Out Charge</u>** – Commencing on June 1, 2024, each Market Participant with a Day-Ahead Ancillary Service obligation shall receive a charge as follows:

(i) **Day-Ahead Generation Contingency Reserve and Day-Ahead Replacement Energy Reserve –** Each MWh of Day-Ahead Ten-Minute Spinning Reserve Obligation, Day-Ahead Ten-Minute Non-Spinning Reserve Obligation, Day-Ahead Thirty-Minute Operating Reserve Obligation, Day-Ahead Ninety-Minute Reserve Obligation, and Day-Ahead Four-Hour Reserve Obligation shall be charged the close-out charge rate, which shall be the greater of (a) the hourly Real-Time Hub Price less the Energy Call Option Strike Price for the hour, and (b) zero.

(ii) **Day-Ahead Energy Imbalance Reserve –** Each MWh of Day-Ahead Energy Imbalance Reserve Obligation shall be charged the close out charge rate determined in accordance with subsection (q)(2)(i).

(q)(3) **Allocation of Net Day-Ahead Generation Contingency Reserve and Day-Ahead Replacement Energy Reserve Credits/Charges** – Commencing on June 1, 2024:

(i) The sum total credits calculated in accordance with Sections III.3.2.1(q)(1)(i)-(v) for Day-Ahead Generation Contingency Reserve and Day-Ahead Replacement Energy Reserve shall be charged on an hourly basis to Market Participants based on their pro rata share of the sum of all Market Participants' Real-Time Load Obligation, excluding Real-Time Load Obligation incurred by Storage DARDs;

(ii) The sum total close-out charges calculated in accordance with Section III.3.2.1(q)(2)(i) for Day-Ahead Generation Contingency Reserve and Day-Ahead Replacement Energy Reserve shall be credited on an hourly basis to Market Participants based on their pro rata share of the sum of all Market Participants' Real-Time Load Obligation, excluding Real-Time Load Obligation incurred by Storage DARDs.

(q)(4) **Allocation of Net Day-Ahead Energy Imbalance Reserve Credits/Charge** – Commencing on June 1, 2024:

(i) For purposes of this subsection (q)(4), the ISO will calculate a load deviation amount for each Market Participant. The load deviation shall be equal to the greater of (a) the MWh amount of the Market Participant's Real-Time Load Obligation (excluding Real-Time Load Obligation incurred by Storage DARDs) minus its Day-Ahead Load Obligation (excluding Day-Ahead Load Obligation incurred by Storage DARDs), or (b) zero.

(ii) The sum of credits calculated in accordance with Section III.3.2.1(q)(1)(vi) for Day-Ahead Energy Imbalance Reserve, if non-zero, shall be charged to Market Participants on an hourly basis as follows:

If the sum of (a) all Market Participants' load deviations and (b) accepted Increment Offers is

equal to or less than the total Day-Ahead Energy Imbalance Reserve Obligation amount, each Market Participant shall be charged: (1) the Day-Ahead Energy Imbalance Reserve clearing price, calculated in accordance with Section III.2.6.2(a)(vi) of this Market Rule 1, multiplied by the Market Participant's accepted Increment Offer amount, and (2) the Day-Ahead Energy Imbalance Reserve clearing price multiplied by the Market Participant's load deviation amount. The balance of any remaining credits for Day-Ahead Energy Imbalance Reserve Obligation shall be charged to Market Participants based on their pro rata share of the sum of all Market Participants' Real-Time Load Obligation, excluding Real-Time Load Obligation incurred by Storage DARDs.

If the sum of (a) all Market Participants' load deviations and (b) accepted Increment Offers is greater than the total Day-Ahead Energy Imbalance Reserve Obligation amount, and if the sum of all Market Participants' load deviations is greater than zero, each Market Participant shall be charged the Day-Ahead Energy Imbalance Reserve clearing price, calculated in accordance with Section III.2.6.2(a)(vi) of this Market Rule 1, multiplied by the Market Participant's accepted Increment Offer amount. The balance of any remaining credits for Day-Ahead Energy Imbalance Reserve Obligation shall be charged to Market Participants based on their pro rata share of the sum of all Market Participants' load deviations.

If the sum of all Market Participants' accepted Increment Offers is greater than the total Day-Ahead Energy Imbalance Reserve Obligation amount, and if the sum of all Market Participants' load deviations is zero, each MWh of a Market Participant's accepted Increment Offer shall be charged the Day-Ahead Energy Imbalance Reserve clearing price, calculated in accordance with Section III.2.6.2(a)(vi) of this Market Rule 1, multiplied by the total Day-Ahead Energy Imbalance Reserve Obligation amount and divided by the sum of all Market Participants' accepted Increment Offer amounts.

(iii) The sum of close-out charges calculated in accordance with Section III.3.2.1(q)(2)(ii) for Day-Ahead Energy Imbalance Reserve, if non-zero, shall be allocated to Market Participants on an hourly basis as follows:

If the sum of (a) all Market Participants' load deviations and (b) accepted Increment Offers is equal to or less than the total Day-Ahead Energy Imbalance Reserve Obligation amount, each Market Participant shall be credited an amount equal to: (1) close-out charge rate determined in

accordance with Section III.3.2.1(q)(2)(ii) for the settlement interval multiplied by the Market Participant's accepted Increment Offer amount, and (2) the close-out charge rate determined in accordance with Section III.3.2.1(q)(2)(ii) for the settlement interval, multiplied by their load deviation amount. The balance of any remaining charges for Day-Ahead Energy Imbalance Reserve Obligations shall be credited to Market Participants based on their pro rata share of the sum of all Market Participants' Real-Time Load Obligation, excluding Real-Time Load Obligation incurred by Storage DARDs.

If the sum of (a) all Market Participants' load deviations and (b) accepted Increment Offers is greater than the total Day-Ahead Energy Imbalance Reserve Obligation amount, and if the sum of all Market Participants' load deviations is greater than zero, each Market Participant shall be credited an amount equal to the close-out charge rate determined in accordance with Section III.3.2.1(q)(2)(ii) for the settlement interval multiplied by the Market Participant's accepted Increment Offer amount. The balance of any remaining charges for Day-Ahead Energy Imbalance Reserve Obligation shall be credited to Market Participants based on their pro rata share of the sum of all Market Participants' load deviations.

If the sum of all Market Participants' accepted increment Offers is greater than the total Day-Ahead Energy Imbalance Reserve Obligation amount, and if the sum of all Market Participants' load deviations is zero, each MWh of a Market Participant's accepted Increment Offer shall be credited an amount equal to the close-out charge rate determined in accordance with Section III.3.2.1(q)(2)(ii) for the settlement interval multiplied by the Market Participant's accepted Increment Offer amount, multiplied by the total Day-Ahead Energy Imbalance Reserve Obligation amount and divided by the sum of all Market Participants' accepted Increment Offer amounts.

(q)(5) **Forecast Energy Requirement Credit** - Commencing on June 1, 2024, Market Participants with Generator Assets, Demand Response Resources, and External Transactions for the supply of energy scheduled in the Day-Ahead Energy Market shall be credited the Forecast Energy Requirement Price, calculated in accordance with Section III.2.6.2(a)(vii), for each MWh of the resource's Day-Ahead energy obligation.

(q)(6) **Forecast Energy Requirement Charge** – The total amount credited in accordance with Section III.3.2.1(q)(5) shall be charged on an hourly basis to Market Participants as follows:

(i) Market Participants shall be charged the Forecast Energy Requirement Price, calculated in accordance with Section III.2.6.2(a)(vii), for each MWh of the Market Participant's Day-Ahead External Transaction sales.

(ii) The balance of any remaining credits shall be charged to Market Participants based on their pro rata share of the sum of all Market Participants' Real-Time Load Obligations, excluding Real-Time Load Obligations incurred by Real-Time External Transaction sales and Storage DARDs.

III.3.2.1.1 Metered Quantity For Settlement.

For purposes of determining the Metered Quantity For Settlement, the five-minute telemetry value for a five-minute interval is the integrated value of telemetered data sampled over the five-minute period. For settlement calculations that require hourly revenue quality meter value from Resources that submit five-minute revenue quality meter data, the hourly revenue quality meter value is the average of five-minute revenue quality meter values for the hour. The Metered Quantity For Settlement is calculated as follows:

(a) For external interfaces, the Metered Quantity For Settlement is the scheduled value adjusted for any curtailment, except that for Inadvertent Interchange, the Metered Quantity For Settlement is the difference between the actual and scheduled values, where the actual value is

(i) calculated as the five-minute telemetry value plus the difference between the hourly revenue quality meter value and the hourly average telemetry value, or

(ii) the five-minute revenue quality meter value, if five-minute revenue quality meter data are available.

(b) For Resources submitting five-minute revenue quality meter data (other than Demand Response Resources), the Metered Quantity For Settlement is the five-minute revenue quality meter value.

(c) For Resources with telemetry submitting hourly revenue quality meter data, the Metered Quantity For Settlement is calculated as follows:

(i) In the event that in an hour, the difference between the average of the five-minute telemetry values for the hour and the revenue quality meter value for the hour is greater than 20 percent of the hourly revenue quality meter value and greater than 10 MW then the Metered Quantity For Settlement is a flat profile of the revenue quality meter value equal to the hourly revenue quality meter value equally apportioned over the five-minute intervals in the hour. (For a Continuous Storage Facility, the difference between the

average of the five-minute telemetry values and the revenue quality meter value will be determined using the net of the values submitted by its component Generator Asset and DARD.)

(ii) Otherwise, the Metered Quantity For Settlement is the telemetry profile of the revenue quality meter value equal to the five-minute telemetry value adjusted by a scale factor.

(d) For a Demand Response Resource, the Metered Quantity For Settlement equals the sum of the demand reductions of each of its constituent Demand Response Assets produced in response to a non-zero Dispatch Instruction, with the demand reduction for each such asset calculated pursuant to Section III.8.4.

(e) For Resources without telemetry submitting hourly revenue quality meter data, the Metered Quantity For Settlement is the hourly revenue quality meter value equally apportioned over the five-minute intervals in the hour.

III.3.2.2 Metering and Communication.

(a) Revenue Quality Metering and Telemetry for Assets other than Demand Response Assets

The megawatt-hour data of each Generator Asset, Tie-Line Asset, and Load Asset must be metered and automatically recorded at no greater than an hourly interval using metering located at the asset's point of interconnection, in accordance with the ISO operating procedures on metering and telemetering. This metered value is used for purposes of establishing the hourly revenue quality metering of the asset.

The instantaneous megawatt data of each Generator Asset (except Settlement Only Resources) and each Asset Related Demand must be automatically recorded and telemetered in accordance with the requirements in the ISO operating procedures on metering and telemetering.

(b) Meter Maintenance and Testing for all Assets

Each Market Participant must adequately maintain metering, recording and telemetering equipment and must periodically test all such equipment in accordance with the ISO operating procedures on metering and telemetering. Equipment failures must be addressed in a timely manner in accordance with the requirements in the ISO operating procedures on maintaining communications and metering equipment.

(c) Additional Metering and Telemetry Requirements for Demand Response Assets

(i) Market Participants must report to the ISO in real time a set of telemetry data for each Demand Response Asset associated with a Demand Response Resource. The telemetry values shall measure the real-time demand of Demand Response Assets as measured at their Retail Delivery Points, and shall be reported to the ISO every five minutes. For a

Demand Response Resource to provide TMSR or TMNSR, Market Participants must in addition report telemetry values at least every one minute. Telemetry values reported by Market Participants to the ISO shall be in MW units and shall be an instantaneous power measurement or an average power value derived from an energy measurement for the time interval from which the energy measurement was taken.

(ii) If one or more generators whose output can be controlled is located behind the Retail Delivery Point of a Demand Response Asset, other than emergency generators that cannot operate electrically synchronized to the New England Transmission System, then the Market Participant must also report to the ISO, before the end of the Correction Limit for the Data Reconciliation Process, a single set of meter data, at an interval of five minutes, representing the combined output of all generators whose output can be controlled.

(iii) If the Market Participant or the ISO finds that the metering or telemetry devices do not meet the accuracy requirements specified in the ISO New England Manuals and Operating Procedures, the Market Participant shall promptly notify the ISO and indicate when it expects to resolve the accuracy problem(s), or shall request that the affected Demand Response Assets be retired. Once such an issue becomes known and until it is resolved, the demand reduction value and Operating Reserve capability of any affected Demand Response Asset shall be excluded from the Demand Response Resource with which it is associated.

(iv) The ISO may review and audit testing and calibration records, audit facility performance (including review of facility equipment), order and witness the testing of metering and telemetry measurement equipment, and witness the demand reduction activities of any facility or generator associated with a Demand Response Asset. Market Participants must make retail billing meter data and any interval meter data from the Host Participant for the facilities associated with a Demand Response Asset available to the ISO upon request.

(d) Overuse of Flat Profiling

In the event a Market Participant's telemetry is replaced with an hourly flat profile pursuant to Section III.3.2.1.1(c)(i) more than 20% of the online hours in a month and Market Participant's Resource has been online for over 50 hours in the month, the ISO may consult with the Market Participant for an explanation of the regular use of flat profiling and may request that the Market Participant address any telemetry discrepancies so that flat profiling is not regularly triggered.

Within 10 business days of issuance of such a request, the Market Participant shall provide the ISO with a written plan for remedying the deficiencies, and shall identify in the plan the specific actions to be taken and a reasonable timeline for completing such remediation. The Market Participant shall complete the remediation in accordance with and under the timeline set forth in the written plan.

III.3.2.3 NCPC Credits and Charges.

A Market Participant's NCPC Credits and NCPC Charges are calculated pursuant to Appendix F to Market Rule 1.

III.3.2.4 Transmission Congestion.

Market Participants shall be charged or credited for Congestion Costs as specified in Section III.3.2.1(i) of this Market Rule 1.

III.3.2.5 [Reserved.]

III.3.2.6 Emergency Energy.

(a) For each settlement interval during an hour in which there are Emergency Energy purchases, the ISO calculates an Emergency Energy purchase charge or credit equal to the Emergency Energy purchase price minus the External Node Real-Time LMP for the interval, multiplied by the Emergency Energy quantity for the interval. The charge or credit for each interval in an hour is summed to an hourly value. The ISO allocates the hourly charges or credits to Market Participants based on the following hourly deviations where such deviations are negative: (i) Real-Time Adjusted Load Obligation Deviations during that Operating Day; (ii) generation deviations and demand reduction deviations for those Pool-Scheduled Resources and Continuous Storage Generator Assets that are not following Dispatch Instructions; Self-Scheduled Resources (other than Continuous Storage Generator Assets) with dispatchable capability above their Self-Scheduled amounts not following Dispatch Instructions; and Self-Scheduled Resources (other than Continuous Storage Generator Assets) not following their Day-Ahead Self-Scheduled amounts other than those following Dispatch Instructions; in MWhs during the Operating Day; and (iii) deviations from the Day-Ahead Energy Market for External Transaction purchases in MWhs during the Operating Day except that positive Real-Time Generation Obligation Deviation at External Nodes associated with Emergency Energy purchases are not included in this calculation. Generator Assets and Demand Response Resources shall have a 5% or 5 MWh threshold when determining such deviations. Notwithstanding the foregoing, the allocation of costs or credits attributable to the purchase of Emergency

Energy from other Control Areas shall exclude contributions to deviations from Coordinated External Transactions.

(b) For each settlement interval during an hour in which there are Emergency Energy sales, the ISO calculates Emergency Energy sales revenue, exclusive of revenue from the Real-Time Energy Market, received from other Control Areas to provide the Emergency Energy sales. The revenues for each interval in an hour is summed to an hourly value. Hourly net revenues attributable to the sale of Emergency Energy to other Control Areas shall be credited to Market Participants based on the following deviations where such deviations are negative: (i) Real-Time Adjusted Load Obligation Deviations in MWhs during that Operating Day; (ii) generation deviations and demand reduction deviations for those Pool-Scheduled Resources and Continuous Storage Generator Assets that are following Dispatch Instructions; and Self-Scheduled Generator Assets (other than Continuous Storage Generator Assets) with dispatchable capability above their Self-Scheduled amounts following Dispatch Instructions; in MWhs during the Operating Day; and (iii) deviations from the Day-Ahead Energy Market for External Transaction purchases in MWhs during the Operating Day except that positive Real-Time Generation Obligation Deviation at External Nodes associated with Emergency Energy purchases are not included in this calculation. Generator Assets and Demand Response Resources shall have a 5% or 5 MWh threshold when determining such deviations. Notwithstanding the foregoing, the calculation of the credit for the sale of Emergency Energy to other Control Areas shall exclude contributions to deviations from Coordinated External Transactions.

III.3.2.6A New Brunswick Security Energy.

New Brunswick Security Energy is energy that is purchased from the New Brunswick System Operator by New England to preserve minimum flows on the Orrington-Keswick (396/3001) tie line and Orrington-Lepreau (390/3016) tie line in accordance with the applicable ISO / New Brunswick System Operator transmission operating guide with respect to the determination of minimum transfer limits. New Brunswick Security Energy costs are hourly costs in excess of the LMP at the applicable External Node attributable to purchases of New Brunswick Security Energy by New England. New Brunswick Security Energy costs shall be allocated among Market Participants on the basis of their pro-rata shares of Regional Network Load. Where the LMP at the applicable External Node exceeds the New Brunswick Security Energy costs, such amounts shall be accounted for in accordance with Section III.3.2.1(m).

III.3.2.7 Billing.

The ISO shall prepare a billing statement each billing cycle, in accordance with the ISO New England Billing Policy, for each Market Participant in accordance with the charges and credits specified in Sections III.3.2.1 through III.3.2.6, and showing the net amount to be paid or received by the Market Participant. Billing statements shall provide sufficient detail, as specified in the ISO New England Manuals, ISO New England Administrative Procedures and the ISO New England Billing Policy, to allow verification of the billing amounts and completion of the Market Participant's internal accounting. Billing disputes shall be settled in accordance with procedures specified in the ISO New England Billing Policy.

III.3.3 [Reserved.]

III.3.4 Non-Market Participant Transmission Customers.

III.3.4.1 Transmission Congestion.

Non-Market Participant Transmission Customers shall be charged or credited for Congestion Costs as specified in Section III.1 of this Market Rule 1.

III.3.4.2 Transmission Losses.

Non-Market Participant Transmission Customers shall be charged or credited for transmission losses in an amount equal to the product of (i) the Transmission Customer's MWhs of deliveries in the Real-Time Energy Market, multiplied by (ii) the difference between the Loss Components of the Real-Time Locational Marginal Prices at the point-of-receipt and the point-of-delivery Locations.

III.3.4.3 Billing.

The ISO shall prepare a billing statement each billing cycle, in accordance with the ISO New England Billing Policy, for each Non-Market Participant Transmission Customer in accordance with the charges and credits specified in Sections III.3.4.1 through III.3.4.2 of this Market Rule 1, and showing the net amount to be paid or received by the Non-Market Participant Transmission Customer. Billing statements shall provide sufficient detail, as specified in the ISO New England Manuals, the ISO New England Administrative Procedures and the ISO New England Billing Policy, to allow verification of the billing amounts and completion of the Non-Market Participant Transmission Customer's internal accounting. Billing disputes shall be settled in accordance with procedures specified in the ISO New England Billing Policy.

III.3.5 [Reserved.]

III.3.6 Data Reconciliation.

III.3.6.1 Data Correction Billing.

The ISO will reconcile Market Participant data errors and corrections after the Correction Limit for such data has passed. The Correction Limit for meter data and for ISO errors in the processing of meter and other Market Participant data is 101 days from the last Operating Day of the month to which the data applied. Notification of Meter Data Errors applicable to Assigned Meter Reader or Host Participant Assigned Meter Reader supplied meter data must be submitted to the ISO by the Meter Data Error RBA Submission Limit.

III.3.6.2 Eligible Data.

The ISO will accept revised hourly asset meter readings from Assigned Meter Readers and Host Participant Assigned Meter Readers, daily Coincident Peak Contribution values from Assigned Meter Readers, and new or revised internal bilateral transactions from Market Participants. No other revised data will be accepted for use in settlement recalculations. The ISO will correct data handling errors associated with other Market Participant supplied data to the extent that such data did not impact unit commitment or the Real-Time dispatch. Data handling errors that impacted unit commitment or the Real-Time dispatch will not be corrected.

III.3.6.3 Data Revisions.

The ISO will accept revisions to asset specific meter data, daily Coincident Peak Contribution values, and internal bilateral transactions prior to the Correction Limit. No revisions to other Market Participant data will be accepted after the deadlines specified in the ISO New England Manuals for submittal of that data have passed, except as provided in Section III.3.8 of Market Rule 1. If the ISO discovers a data error or if a Market Participant discovers and notifies the ISO of a data error prior to the Correction Limit, revised hourly data will be used to recalculate all markets and charges as appropriate, including but not limited to energy, NCPC, Regulation, Operating Reserves, Auction Revenue Rights allocations, Forward Capacity Market, cost-of-service agreements, and the ISO Tariff. No settlement recalculations or other adjustments may be made if the Correction Limit for the Operating Day to which the error applied has passed or if the correction does not qualify for treatment as a Meter Data Error correction pursuant to Section III.3.8 of Market Rule 1.

III.3.6.4 Meter Corrections Between Control Areas.

For revisions to meter data associated with assets that connect the New England Control Area to other Control Areas, the ISO will, in addition to performing settlement recalculations, adjust the actual interchange between the New England Control Area and the other Control Area to maintain an accurate record of inadvertent energy flow.

III.3.6.5 Meter Correction Data.

(a) Revised meter data and daily Coincident Peak Contribution values shall be submitted to the ISO as soon as it is available and not later than the Correction Limit, and must be submitted in accordance with the criteria specified in Section III.3.7 of Market Rule 1. Specific data submittal deadlines are detailed in the ISO New England Manuals.

(b) Errors on the part of the ISO in the administration of Market Participant supplied data shall be brought to the attention of the ISO as soon as possible and not later than the Correction Limit.

III.3.7 Eligibility for Billing Adjustments.

(a) Errors in Market Participant's statements resulting from errors in settlement software, errors in data entry by ISO personnel, and settlement production problems, that do not affect the day-ahead schedule or real-time system dispatch, will be corrected as promptly as practicable. If errors are identified prior to the issuance of final statements, the market will be resettled based on the corrected information.

(b) Calculations made by scheduling or dispatch software, operational decisions involving ISO discretion which affect scheduling or real-time operation, and the ISO's execution of mandatory dispatch directions, such as self-schedules or external contract conditions, are not subject to retroactive correction and resettlement. The ISO will settle and bill the Day-Ahead Energy Market as actually scheduled and the Real-Time Energy Market as actually dispatched. Any post-settlement issues raised concerning operating decisions related to these markets will be corrected through revision of operations procedures and guidelines on a prospective basis.

(c) While errors in reporting hourly metered data may be corrected (pursuant to Section III.3.8), Market Participants have the responsibility to ensure the correctness of all data they submit to the market settlement system.

(d) Disputes between Market Participants regarding settlement of internal bilateral transactions shall not be subject to adjustment by the ISO, but shall be resolved directly by the Market Participants unless they involve an error by the ISO that is subject to resolution under Section III.3.7(a).

(e) Billing disputes between Market Participants and the ISO or Non-Market Participants and the ISO shall be settled in accordance with procedures specified in the ISO New England Billing Policy.

(f) Criteria for Meter Data Errors to be eligible for a Requested Billing Adjustment. In order to be eligible to submit a Requested Billing Adjustment due to a Meter Data Error on an Invoice issued by the ISO after the completion of the Data Reconciliation Process, a Market Participant must satisfy one of the following two conditions: (1) the Meter Data Error at issue was identified by the asset owner, Assigned Meter Reader or the Host Participant Assigned Meter Reader and communicated to the Host Participant Assigned Meter Reader no later than thirty-six (36) days prior to the Correction Limit for Directly Metered Assets and no later than two (2) days prior to the Correction Limit for Profiled Load Assets and could not be resolved prior to those deadlines; or (2) the Meter Data Error at issue was identified by the asset owner, Assigned Meter Reader or Host Participant Assigned Meter Reader and reported to the ISO by the Meter Data Error RBA Submission Limit, and such Meter Data Error represents an error that is equal to or greater than the 1,000 MWh per Asset over a calendar month. If the Meter Data Error affects more than one metering domain, the ISO, and affected Host Participant Assigned Meter Readers and affected Assigned Meter Readers of affected metering domains, must be notified.

III.3.8 Correction of Meter Data Errors

(a) Any Market Participant, Assigned Meter Reader or Host Participant Assigned Meter Reader may submit notification of a Meter Data Error in accordance with the procedures provided in this Section III.3.8, provided that the notification is submitted no later than the Meter Data Error RBA Submission Limit and that the notice must be submitted using the RBA form for Meter Data Errors posted on the ISO's website. Errors in telemetry values used in calculating Metered Quantity For Settlement are not eligible for correction under this Section III.3.8.

(b) Within three Business Days of the receipt by the ISO's Chief Financial Officer of an RBA form for a Meter Data Error, the ISO shall prepare and submit to all Covered Entities and to the Chair of the NEPOOL Budget and Finance Subcommittee a notice of the Meter Data Error correction ("Notice of Meter Data Error Correction"), including, subject to the provisions of the ISO New England Information Policy, the specific details of the correction and the identity of the affected metering domains and the

affected Host Participant Assigned Meter Readers. The "Notice of Meter Data Error Correction" shall identify a specific representative of the ISO to whom all communications regarding the matter are to be sent.

(c) In order for a Meter Data Error on an Invoice issued by the ISO after the completion of the Data Reconciliation Process to be eligible for correction, the Meter Data Error must satisfy one of the following conditions: (1) the Meter Data Error at issue was identified by the asset owner, Assigned Meter Reader or the Host Participant Assigned Meter Reader and communicated to the Host Participant Assigned Meter Reader no later than 36 days prior to the Correction Limit for Directly Metered Assets and no later than two days prior to the Correction Limit for Profiled Load Assets and could not be resolved prior to those deadlines; (2) the Meter Data Error at issue was identified by the asset owner, Assigned Meter Reader or Host Participant Assigned Meter Reader, and such Meter Data Error represents an error that is equal to or greater than the 1,000 MWh per asset over a calendar month; and (3) if the Meter Data Error involves only Coincident Peak Contribution values, the average of the daily Meter Data Errors involving Coincident Peak Contribution values for the affected calendar month must be greater than or equal to 5 MW for an affected asset. If the Meter Data Error affects more than one metering domain, the ISO, and affected Host Participant Assigned Meter Readers and affected Assigned Meter Readers of affected metering domains, must be notified.

(d) For a Meter Data Error, the Host Participant Assigned Meter Reader must submit to the ISO corrected meter data for Directly Metered Assets prior to the 46th calendar day after the Meter Data Error RBA Submission Limit. Corrected metered data for Profiled Load Assets and Coincident Peak Contribution values, must be submitted to the ISO by the Host Participant Assigned Meter Reader prior to the 87th calendar day after the Meter Data Error RBA Submission Limit. Corrected internal bilateral transactions data must be submitted to the ISO by a Market Participant prior to the 91st calendar day after the Meter Data Error RBA Submission Limit.

Any corrected data received after the specified deadlines is not eligible for use in the settlement process.

The Host Participant Assigned Meter Reader or Market Participant, as applicable, must confirm as part of its submission of corrected data that the eligibility criteria described in Section III.3.8(c) of Market Rule 1 have been satisfied.

To the extent that the correction of a Meter Data Error is for a Directly Metered Asset that affects multiple metering domains, all affected Host Participant Assigned Meter Readers or Assigned Meter Readers must notify the ISO prior to the 46th calendar day after the Meter Data Error RBA Submission Limit that the corrected Directly Metered Asset data is acceptable to them in order for the ISO to use the corrected data in the final settlement calculations. The Host Participant Assigned Meter Reader for the Directly Metered Asset is responsible for initiating an e-mail to every affected Host Participant Assigned Meter Reader or Assigned Meter Reader in order to obtain such acceptance and shall coordinate delivery of such acceptance to the ISO. The Host Participant Assigned Meter Reader for the Directly Metered Asset is also responsible for submitting all corrected and agreed upon Directly Metered Asset data to the ISO prior to the 46th calendar day after the Meter Data Error RBA Submission Limit.

(e) After the submission of corrected meter and internal bilateral transactions data, the ISO will have a minimum of 30 calendar days to administer the final settlement based on that data. Revised data will be used to recalculate all charges and credits, except that revised data will not be used to recalculate the PER adjustment, including the Hourly PER and Monthly PER values. Revised data will also not be used to recalculate Demand Resource Seasonal Peak Hours. The results of the final settlement will then be included in the next Invoice containing Non-Hourly Charges and the ISO will provide to the Chair of the NEPOOL Budget and Finance Subcommittee written notification that the final settlement has been administered.

III.4 Rate Table

III.4.1 Offered Price Rates.

Day-Ahead energy, Day-Ahead Ancillary Services as of June 1, 2024, Real-Time energy, Regulation, Real-Time Operating Reserve, Forward Reserve, NCPC, Congestion Cost and transmission loss costs are based on offers and bids submitted to the ISO as specified in this Market Rule 1.

III.4.2 [Reserved.]

III.4.3 Emergency Energy Transaction.

The pricing for Emergency Energy and New Brunswick Security Energy purchases and sales will be determined in accordance with:

(a) an applicable agreement with an adjacent Control Area for Emergency and/or New Brunswick Security Energy purchases and sales, or

(b) arrangements made by the ISO with Market Participants, in accordance with procedures defined in the ISO New England Manuals, to purchase Emergency Energy offered by such Market Participant from External Transactions that are not associated with Import Capacity Resources. The ISO shall select offers to sell Emergency Energy made by Market Participants to the ISO on a least cost basis and the selected Market Participants shall receive payment for energy delivered at the higher of their offer price or the Real-Time Price at the applicable External Node. Such Emergency Energy purchases from Market Participants shall not be eligible to set Real-Time Prices.

III.13.2. Annual Forward Capacity Auction.

III.13.2.1. Timing of Annual Forward Capacity Auctions.

Each Forward Capacity Auction will be conducted beginning on the first Monday in the February that is approximately three years and four months before the beginning of the associated Capacity Commitment Period (unless, no later than the immediately preceding December 1, an alternative date is announced by the ISO), or, where exigent circumstances prevent the start of the Forward Capacity Auction at that time, as soon as possible thereafter.

III.13.2.2. Amount of Capacity Cleared in Each Forward Capacity Auction.

The total amount of capacity cleared in each Forward Capacity Auction shall be determined using the System-Wide Capacity Demand Curve and the Capacity Zone Demand Curves for the modeled Capacity Zones pursuant to Section III.13.2.3.3.

III.13.2.2.1. System-Wide Capacity Demand Curve.

The MRI Transition Period is the period from the Forward Capacity Auction for the Capacity Commitment Period beginning June 1, 2020 through the earlier of:

(i) the Forward Capacity Auction for which the amount of the Installed Capacity Requirement (net of HQICCs) that is filed by the ISO with the Commission pursuant to Section III.12.3 for the upcoming Forward Capacity Auction is greater than or equal to the sum of: 34,151 MW, and: (a) 722 MW (for the Forward Capacity Auction for the Capacity Commitment Period beginning June 1, 2020); (b) 375 MW (for the Forward Capacity Auction for the Capacity Commitment Period beginning June 1, 2021), or; (c) 150 MW (for the Forward Capacity Auction for the Capacity Commitment Period beginning June 1, 2022);

(ii) the Forward Capacity Auction for which the product of the system-wide Marginal Reliability Impact value, calculated pursuant to Section III.12.1.1, and the scaling factor specified in Section III.13.2.2.4, specifies a quantity at $7.03/kW-month in excess of the MW value determined under the applicable subsection (2)(b), (2)(c), or (2)(d), below, or;

(iii) the Forward Capacity Auction for the Capacity Commitment Period beginning June 1, 2022.

During the MRI Transition Period, the System-Wide Capacity Demand Curve shall consist of the following three segments:

(1) at prices above $7.03/kW-month and below the Forward Capacity Auction Starting Price, the System-Wide Capacity Demand Curve shall specify a price for system capacity quantities based on the product of the system-wide Marginal Reliability Impact value, calculated pursuant to Section III.12.1.1, and the scaling factor specified in Section III.13.2.2.4;

(2) at prices below $7.03/kW-month, the System-Wide Capacity Demand Curve shall be linear between $7.03/kW-month and $0.00/kW-month and determined by the following quantities:

(a) At the price of $0.00/kW-month, the quantity specified by the System-Wide Capacity Demand Curve shall be 1616 MW plus the MW value determined under the applicable provision in (b), (c), or (d) of this subsection.

(b) for the Forward Capacity Auction for the Capacity Commitment Period beginning June 1, 2020, at $7.03/kW-month, the quantity shall be the lesser of:

1. 35,437 MW; and
2. 722 MW plus the quantity at which the product of the system-wide Marginal Reliability Impact value and the scaling factor yield a price of $7.03/kW-month;

(c) for the Forward Capacity Auction for the Capacity Commitment Period beginning June 1, 2021, at $7.03/kW-month, the quantity shall be the lesser of:

1. 35,090 MW; and
2. 375 MW plus the quantity at which the product of the system-wide Marginal Reliability Impact value and the scaling factor yield a price of $7.03/kW-month;

(d) for the Forward Capacity Auction for the Capacity Commitment Period beginning June 1, 2022, at $7.03/kW-month, the quantity shall be the lesser of:

1. 34,865 MW; and
2. 150 MW plus the quantity at which the product of the system-wide Marginal Reliability Impact value and the scaling factor yield a price of $7.03/kW-month

(3) a price of $7.03/kW-month for all quantities between those curves segments.

In addition to the foregoing, the System-Wide Capacity Demand Curve shall not specify a price in excess of the Forward Capacity Auction Starting Price.

Following the MRI Transition Period, the System-Wide Capacity Demand Curve shall specify a price for system capacity quantities based on the product of the system-wide Marginal Reliability Impact value, calculated pursuant to Section III.12.1.1, and the scaling factor specified in Section III.13.2.2.4. For any system capacity quantity greater than 110% of the Installed Capacity Requirement (net of HQICCs), the System-Wide Capacity Demand Curve shall specify a price of zero. The System-Wide Capacity Demand Curve shall not specify a price in excess of the Forward Capacity Auction Starting Price.

III.13.2.2.2. Import-Constrained Capacity Zone Demand Curves.

For each import-constrained Capacity Zone, the Capacity Zone Demand Curve shall specify a price for all Capacity Zone quantities based on the product of the import-constrained Capacity Zone's Marginal Reliability Impact value, calculated pursuant to Section III.12.2.1.3, and the scaling factor specified in Section III.13.2.2.4. The prices specified by an import-constrained Capacity Zone Demand Curve shall be non-negative. At all quantities greater than the truncation point, which is the amount of capacity for which the Capacity Zone Demand Curve specifies a price of $0.01/kW-month, the Capacity Zone Demand Curve shall specify a price of zero. The Capacity Zone Demand Curve shall not specify a price in excess of the Forward Capacity Auction Starting Price.

III.13.2.2.3. Export-Constrained Capacity Zone Demand Curves.

For each export-constrained Capacity Zone, the Capacity Zone Demand Curve shall specify a price for all Capacity Zone quantities based on the product of the export-constrained Capacity Zone's Marginal Reliability Impact value, calculated pursuant to Section III.12.2.2.1, and the scaling factor specified in Section III.13.2.2.4. The prices specified by an export-constrained Capacity Zone Demand Curve shall be non-positive. At all quantities less than the truncation point, which is the amount of capacity for which the Capacity Zone Demand Curve specifies a price of negative $0.01/kW-month, the Capacity Zone Demand Curve shall specify a price of zero.

III.13.2.2.4. Capacity Demand Curve Scaling Factor.

The demand curve scaling factor shall be set at the value such that, at the quantity specified by the System-Wide Capacity Demand Curve at a price of Net CONE, the Loss of Load Expectation is 0.1 days per year.

III.13.2.3. Conduct of the Forward Capacity Auction.

The Forward Capacity Auction shall include a descending clock auction, which will determine, subject to the provisions of Section III.13.2.7, the Capacity Clearing Price for each Capacity Zone modeled in that Forward Capacity Auction pursuant to Section III.12.4, and the Capacity Clearing Price for certain offers from New Import Capacity Resources and Existing Import Capacity Resources pursuant to Section III.13.2.3.3(d). The Forward Capacity Auction shall determine the outcome of all offers and bids accepted during the qualification process and submitted during the auction. The descending clock auction shall be conducted as a series of rounds, which shall continue (for up to five consecutive Business Days, with up to eight rounds per day, absent extraordinary circumstances) until the Forward Capacity Auction is concluded for all modeled Capacity Zones in accordance with the provisions of Section III.13.2.3.3. Each round of the Forward Capacity Auction shall consist of the following steps, which shall be completed simultaneously for each Capacity Zone included in the round:

III.13.2.3.1. Step 1: Announcement of Start-of-Round Price and End-of-Round Price.

For each round, the auctioneer shall announce a single Start-of-Round Price (the highest price associated with a round of the Forward Capacity Auction) and a single (lower) End-of-Round Price (the lowest price associated with a round of the Forward Capacity Auction). In the first round, the Start-of-Round Price shall equal the Forward Capacity Auction Starting Price for all modeled Capacity Zones. In each round after the first round, the Start-of-Round Price shall equal the End-of-Round Price from the previous round.

III.13.2.3.2. Step 2: Compilation of Offers and Bids.

The auctioneer shall compile all of the offers and bids for that round, as follows:

(a) **Offers from New Generating Capacity Resources, New Import Capacity Resources, and New Demand Capacity Resources.**

(i) The Project Sponsor for any New Generating Capacity Resource, New Import Capacity Resource that is backed by a single new External Resource and that is associated with an investment in transmission that increases New England’s import capability, New Import Capacity

Resource that is associated with an Elective Transmission Upgrade, or New Demand Capacity Resource accepted in the qualification process for participation in the Forward Capacity Auction may submit a New Capacity Offer indicating the quantity of capacity that the Project Sponsor would commit to provide from the resource during the Capacity Commitment Period at that round's prices. A New Capacity Offer shall be defined by the submission of one to five prices, each strictly less than the Start-of-Round Price but greater than or equal to the End-of-Round Price, and an associated quantity in the applicable Capacity Zone. Each price shall be expressed in units of dollars per kilowatt-month to an accuracy of at most three digits to the right of the decimal point, and each quantity shall be expressed in units of MWs to an accuracy of at most three digits to the right of the decimal point. A New Capacity Offer shall imply a supply curve indicating quantities offered at all of that round's prices, pursuant to the convention of Section III.13.2.3.2(a)(iii).

(ii) If the Project Sponsor of a New Generating Capacity Resource, New Import Capacity Resource that is backed by a single new External Resource and that is associated with an investment in transmission that increases New England's import capability, New Import Capacity Resource that is associated with an Elective Transmission Upgrade, or New Demand Capacity Resource elects to offer in a Forward Capacity Auction, the Project Sponsor must offer the resource's full FCA Qualified Capacity at the Forward Capacity Auction Starting Price in the first round of the auction. A New Capacity Offer for a resource may in no event be for greater capacity than the resource's full FCA Qualified Capacity at any price. A New Capacity Offer for a resource may not be for less capacity than the resource's Rationing Minimum Limit at any price, except where the New Capacity Offer is for a capacity quantity of zero.

(iii) Let the Start-of-Round Price and End-of-Round Price for a given round be P_S and P_E, respectively. Let the m prices ($1 \leq m \leq 5$) submitted by a Project Sponsor for a modeled Capacity Zone be $p_1, p_2, \ldots, p_m$, where $P_S > p_1 > p_2 > \ldots > p_m \geq P_E$, and let the associated quantities submitted for a New Capacity Resource be $q_1, q_2, \ldots, q_m$. Then the Project Sponsor's supply curve, for all prices strictly less than P_S but greater than or equal to P_E, shall be taken to be:

$$S(p)=\begin{cases} q_0, & \text{if } p > p_1, \\ q_1, & \text{if } p_2 < p \le p_1, \\ q_2, & \text{if } p_3 < p \le p_2, \\ \cdots & \cdots \quad , \\ q_m, & \text{if } p \le p_m. \end{cases}$$

where, in the first round, q_0 is the resource's full FCA Qualified Capacity and, in subsequent rounds, q_0 is the resource's quantity offered at the lowest price of the previous round.

(iv) Except for Renewable Technology Resources and except as provided in Section III.13.2.3.2(a)(v), a New Capacity Resource may not include any capacity in a New Capacity Offer during the Forward Capacity Auction at any price below the resource's New Resource Offer Floor Price. The amount of capacity included in each New Capacity Offer at each price shall be included in the aggregate supply curves at that price as described in Section III.13.2.3.3.

(v) Capacity associated with a New Import Capacity Resource (other than a New Import Capacity Resource that is backed by a single new External Resource and that is associated with an investment in transmission that increases New England's import capability or a New Import Capacity Resource that is associated with an Elective Transmission Upgrade) shall be automatically included in the aggregate supply curves as described in Section III.13.2.3.3 at prices at or above the resource's offer prices (as they may be modified pursuant to Section III.A.21.2) and shall be automatically removed from the aggregate supply curves at prices below the resource's offer prices (as they may be modified pursuant to Section III.A.21.2), except under the following circumstances:

In any round of the Forward Capacity Auction in which prices are below the Dynamic De-List Bid Threshold, the Project Sponsor for a New Import Capacity Resource (other than a New Import Capacity Resource that is backed by a single new External Resource and that is associated with an investment in transmission that increases New England's import capability or a New Import Capacity Resource that is associated with an Elective Transmission Upgrade) with offer prices (as they may be modified pursuant to Section III.A.21.2) that are less than the Dynamic Delist Bid Threshold may submit a New Capacity Offer indicating the quantity of capacity that the Project Sponsor would commit to provide from the resource during the Capacity Commitment Period at that round's prices. Such an offer shall be defined by the submission of one to five

prices, each less than the Dynamic De-List Bid Threshold (or the Start-of-Round Price, if lower than the Dynamic De-List Bid Threshold) but greater than or equal to the End-of-Round Price, and a single quantity associated with each price. Such an offer shall be expressed in the same form as specified in Section III.13.2.3.2(a)(i) and shall imply a curve indicating quantities at all of that round's relevant prices, pursuant to the convention of Section III.13.2.3.2(a)(iii). The curve may not increase the quantity offered as the price decreases.

(b) **Bids from Existing Capacity Resources**

(i) Static De-List Bids, Permanent De-List Bids, Retirement De-List Bids, and Export Bids from Existing Generating Capacity Resources, Existing Import Capacity Resources, and Existing Demand Capacity Resources, as finalized in the qualification process or as otherwise directed by the Commission shall be automatically bid into the appropriate rounds of the Forward Capacity Auction, such that each such resource's FCA Qualified Capacity will be included in the aggregate supply curves as described in Section III.13.2.3.3 until any Static De-List Bid, Permanent De-List Bid, Retirement D-List Bid, or Export Bid clears in the Forward Capacity Auction, as described in Section III.13.2.5.2, and is removed from the aggregate supply curves. In the case of a Commission-approved Permanent De-List Bid or Commission-approved Retirement De-List Bid at or above the Forward Capacity Auction Starting Price, or where a Permanent De-List Bid or Retirement De-List Bid is subject to an election under Section III.13.1.2.4.1(a), the resource's FCA Qualified Capacity will be reduced by the quantity of the de-list bid (unless the resource was retained for reliability pursuant to Section III.13.1.2.3.1.5.1) and the Permanent De-List Bid or Retirement De-List Bid shall not be included in the Forward Capacity Auction. Permanent De-List Bids and Retirement De-List Bids subject to an election under Section III.13.1.2.4.1(a) or Section III.13.1.2.4.1(b) shall not be included in the Forward Capacity Auction and shall be treated according to Section III.13.2.3.2(b)(ii). In the case of a Static De-List Bid, if the Market Participant revised the bid pursuant to Section III.13.1.2.3.1.1, then the revised bid shall be used in place of the submitted bid; if the Market Participant withdrew the bid pursuant to Section III.13.1.2.3.1.1, then the capacity associated with the withdrawn bid shall be entered into the auction pursuant to Section III.13.2.3.2(c). If the amount of capacity associated with Export Bids for an interface exceeds the transfer limit of that interface (minus any accepted Administrative De-List Bids over that interface), then the set of Export Bids associated with that interface equal to the interface's transfer limit (minus any accepted Administrative De-List Bids over that interface) having the highest bid prices shall be included in the auction as described above;

capacity for which Export Bids are not included in the auction as a result of this provision shall be entered into the auction pursuant to Section III.13.2.3.2(c).

(ii) For Permanent De-List Bids and Retirement De-List Bids, the ISO will enter a Proxy De-List Bid into the appropriate rounds of the Forward Capacity Auction in the following circumstances: (1) if the Lead Market Participant has elected pursuant to Section III.13.1.2.4.1(a) to retire the resource or portion thereof, the resource has not been retained for reliability pursuant to Section III.13.1.2.3.1.5.1, the price specified in the Commission-approved de-list bid is less than the Forward Capacity Auction Starting Price, and the Internal Market Monitor has found a portfolio benefit pursuant to Section III.A.24; or (2) if the Lead Market Participant has elected conditional treatment pursuant to Section III.13.1.2.4.1(b), the resource has not been retained for reliability pursuant to Section III.13.1.2.3.1.5.1, and the price specified in the Commission-approved de-list bid is less than the price specified in the de-list bid submitted by the Lead Market Participant and less than the Forward Capacity Auction Starting Price. The Proxy De-List Bid shall be non-rationable and shall be equal in price and quantity to, and located in the same Capacity Zone as, the Commission-approved Permanent De-List Bid or Commission-approved Retirement De-List Bid, and shall be entered into the appropriate rounds of the Forward Capacity Auction such that the capacity associated with the Proxy De-List Bid will be included in the aggregate supply curves as described in Section III.13.2.3.3 until the Proxy De-List Bid clears in the Forward Capacity Auction, as described in Section III.13.2.5.2, and is removed from the aggregate supply curves. If the Lead Market Participant has elected conditional treatment pursuant to Section III.13.1.2.4.1(b), the resource has not been retained for reliability pursuant to Section III.13.1.2.3.1.5.1, and the Commission-approved Permanent De-List Bid or Commission-approved Retirement De-List Bid is equal to or greater than the de-list bid submitted by the Lead Market Participant, no Proxy De-List Bid shall be used and the Commission-approved de-list bid shall be entered in the Forward Capacity Auction pursuant to Section III.13.2.3.2(b)(i).

(iii) For purposes of this subsection (b), if an Internal Market Monitor-determined price has been established for a Static De-List Bid and the associated resource's capacity is pivotal pursuant to Sections III.A.23.1 and III.A.23.2, then (unless otherwise directed by the Commission) the lower of the Internal Market Monitor-determined price and any revised bid that is submitted pursuant to Section III.13.1.2.3.1.1 will be used in place of the initially submitted bid; provided, however, that if the bid was withdrawn pursuant to Section III.13.1.2.3.1.1, then the capacity associated with the withdrawn bid shall be entered into the auction pursuant to

Section III.13.2.3.2(c). If an Internal Market Monitor-determined price has been established for an Export Bid and the associated resource's capacity is pivotal pursuant to Sections III.A.23.1 and III.A.23.2, then the Internal Market Monitor-determined price (or price directed by the Commission) will be used in place of the submitted bid.

Any Static De-List Bid for ambient air conditions that has not been verified pursuant to Section III.13.1.2.3.2.4 shall not be subject to the provisions of this subsection (b).

(c) **Existing Capacity Resources Without De-List or Export Bids and Self-Supplied FCA Resources**. Each Existing Generating Capacity Resource, Existing Import Capacity Resource, and Existing Demand Capacity Resource without a Static De-List Bid, a Permanent De-List Bid, a Retirement De-List Bid, an Export Bid or an Administrative Export De-List Bid in its Existing Capacity Qualification Package, and each existing Self-Supplied FCA Resource shall be automatically entered into each round of the Forward Capacity Auction at its FCA Qualified Capacity, such that the resource's FCA Qualified Capacity will be included in the aggregate supply curves as described in Section III.13.2.3.3, except where such resource, if permitted, submits an appropriate Dynamic De-List Bid, as described in Section III.13.2.3.2(d). Each new Self-Supplied FCA Resource shall be automatically entered into each round of the Forward Capacity Auction at its designated self-supplied quantity at prices at or above the resource's New Resource Offer Floor Price, such that the resource's designated self-supply quantity will be included in the aggregate supply curves as described in Section III.13.2.3.3.

(d) **Dynamic De-List Bids.** In any round of the Forward Capacity Auction in which prices are below the Dynamic De-List Bid Threshold, any Existing Generating Capacity Resource, Existing Import Capacity Resource, or Existing Demand Capacity Resource (but not any Self-Supplied FCA Resources) may submit a Dynamic De-List Bid at prices below the Dynamic De-List Bid Threshold. Such a bid shall be defined by the submission of one to five prices, each less than the Dynamic De-List Bid Threshold (or the Start-of-Round Price, if lower than the Dynamic De-List Bid Threshold) but greater than or equal to the End-of-Round Price, and a single quantity associated with each price. Such a bid shall be expressed in the same form as specified in Section III.13.2.3.2(a)(i) and shall imply a curve indicating quantities at all of that round's relevant prices, pursuant to the convention of Section III.13.2.3.2(a)(iii). The curve may in no case increase the quantity offered as the price decreases. A dynamic De-List Bid may not offer less capacity than the resource's Rationing Minimum Limit at any price, except where the amount of capacity offered is zero. All Dynamic De-List Bids are subject to a reliability review as described in Section III.13.2.5.2.5, and if not rejected for reliability reasons, shall be included in the round in the same

manner as Static De-List Bids as described in Section III.13.2.3.2(b). Where a resource elected pursuant to Section III.13.1.1.2.2.4 or Section III.13.1.4.1.1.2.7 to have the Capacity Supply Obligation and Capacity Clearing Price continue to apply after the Capacity Commitment Period associated with the Forward Capacity Auction in which the offer clears, the capacity associated with any resulting Capacity Supply Obligation may not be subject to a Dynamic De-List Bid in subsequent Forward Capacity Auctions for Capacity Commitment Periods for which the Project Sponsor elected to have the Capacity Supply Obligation and Capacity Clearing Price continue to apply. Where a Lead Market Participant submits any combination of Dynamic De-List Bid, Static De-List Bid, Export Bid, and Administrative Export De-List Bid for a single resource, none of the prices in a set of price-quantity pairs associated with a bid may be the same as any price in any other set of price-quantity pairs associated with another bid for the same resource.

(e) **Repowering**. Offers and bids associated with a resource participating in the Forward Capacity Auction as a New Generating Capacity Resource pursuant to Section III.13.1.1.1.2 (resources previously counted as capacity resources) shall be addressed in the Forward Capacity Auction in accordance with the provisions of this Section III.13.2.3.2(e). The Project Sponsor shall offer such a New Generating Capacity Resource into the Forward Capacity Auction in the same manner and pursuant to the same rules as other New Generating Capacity Resources, as described in Section III.13.2.3.2(a). As long as any capacity is offered from the New Generating Capacity Resource, the amount of capacity offered is the amount that the auctioneer shall include in the aggregate supply curve at the relevant prices, and the quantity of capacity offered from the associated Existing Generating Capacity Resource shall not be included in the aggregate supply curve. If any portion of the New Generating Capacity Resource clears in the Forward Capacity Auction, the associated Existing Generating Capacity Resource shall be permanently de-listed as of the start of the associated Capacity Commitment Period. If at any price, no capacity is offered from the New Generating Capacity Resource, then the auctioneer shall include capacity from the associated Existing Generating Capacity Resource at that price, subject to any bids submitted and accepted in the qualification process for that Existing Generating Capacity Resource pursuant to Section III.13.1.2.5. Bids submitted and accepted in the qualification process for an Existing Generating Capacity Resource pursuant to Section III.13.1.2.5 shall only be entered into the Forward Capacity Auction after the associated New Generating Capacity Resource is fully withdrawn (that is, the Forward Capacity Auction reaches a price at which the resource’s New Capacity Offer is zero capacity), and shall only then be subject to the reliability review described in Section III.13.2.5.2.5.

(f) **Conditional Qualified New Resources.** Offers associated with a resource participating in the Forward Capacity Auction as a Conditional Qualified New Resource pursuant to Section III.13.1.1.2.3(f) shall be addressed in the Forward Capacity Auction in accordance with the provisions of this Section III.13.2.3.2(f). The Project Sponsor shall offer such a Conditional Qualified New Resource into the Forward Capacity Auction in the same manner and pursuant to the same rules as other New Generating Capacity Resources, as described in Section III.13.2.3.2(a). An offer from at most one resource at a Conditional Qualified New Resource's location will be permitted to clear (receive a Capacity Supply Obligation for the associated Capacity Commitment Period) in the Forward Capacity Auction. As long as a positive quantity is offered at the End-of-Round Price in the final round of the Forward Capacity Auction by the resource having a higher queue priority at the Conditional Qualified New Resource's location, as described in Section III.13.1.1.2.3(f), then no capacity from the Conditional Qualified New Resource shall clear. If at any price greater than or equal to the End-of-Round Price in the final round of the Forward Capacity Auction, zero quantity is offered from the resource having higher queue priority at the Conditional Qualified New Resource's location, as described in Section III.13.1.1.2.3(f), then the auctioneer shall consider capacity offered from the Conditional Qualified New Resource in the determination of clearing, including the application of Section III.13.2.7.

(g) **Mechanics**. Offers and bids that may be submitted during a round of the Forward Capacity Auction must be received between the starting time and ending time of the round, as announced by the auctioneer in advance. The ISO at its sole discretion may authorize a participant in the auction to complete or correct its submission after the ending time of a round, but only if the participant can demonstrate to the ISO's satisfaction that the participant was making reasonable efforts to complete a valid offer submission before the ending time of the round, and only if the ISO determines that allowing the completion or correction will not unreasonably disrupt the auction process. All decisions by the ISO concerning whether or not a participant may complete or correct a submission after the ending time of a round are final.

III.13.2.3.3. Step 3: Determination of the Outcome of Each Round.

The auctioneer shall use the offers and bids for the round as described in Section III.13.2.3.2 to determine the aggregate supply curves for the New England Control Area and for each modeled Capacity Zone included in the round.

The aggregate supply curve for the New England Control Area, the Total System Capacity, shall reflect at each price the sum of the following:

(1) the amount of capacity offered in all Capacity Zones modeled as import-constrained Capacity Zones at that price (excluding capacity offered from New Import Capacity Resources and Existing Import Capacity Resources);

(2) the amount of capacity offered in the Rest-of-Pool Capacity Zone at that price (excluding capacity offered from New Import Capacity Resources and Existing Import Capacity Resources);

(3) for each Capacity Zone modeled as an export-constrained Capacity Zone, the lesser of:

(i) the amount of capacity offered in the Capacity Zone at that price (including the amount of capacity offered from New Import Capacity Resources and Existing Import Capacity Resources for each interface between the New England Control Area and an external Control Area mapped to the export-constrained Capacity Zone up to that interface's approved capacity transfer limit (net of tie benefits)), or;

(ii) the amount of capacity determined by the Capacity Zone Demand Curve at zero minus that price, and;

(4) for each interface between the New England Control Area and an external Control Area mapped to an import-constrained Capacity Zone or the Rest-of-Pool Capacity Zone, the lesser of:

(i) that interface's approved capacity transfer limit (net of tie benefits), or;

(ii) the amount of capacity offered from New Import Capacity Resources and Existing Import Capacity Resources.

In computing the Total System Capacity, capacity associated with any New Capacity Offer at any price greater than the Forward Capacity Auction Starting Price will not be included in the tally of total capacity at the Forward Capacity Auction Starting Price for that Capacity Zone. On the basis of these aggregate supply curves, the auctioneer shall determine the outcome of the round for each modeled Capacity Zone as follows:

(a) **Import-Constrained Capacity Zones.**

For a Capacity Zone modeled as an import-constrained Capacity Zone, if either of the following two conditions is met during the round:

(1) the aggregate supply curve for the import-constrained Capacity Zone, adjusted as necessary in accordance with Section III.13.2.6 (Capacity Rationing Rule), equals or is less than the quantity determined by the Capacity Zone Demand Curve at the difference between the End-of-Round Price and the price specified by the System-Wide Capacity Demand Curve (at a quantity no less than Total System Capacity at the Start-of-Round Price), or;

(2) the Forward Capacity Auction is concluded for the Rest-of-Pool Capacity Zone;

then the Forward Capacity Auction for that Capacity Zone is concluded and such Capacity Zone will not be included in further rounds of the Forward Capacity Auction.

The Capacity Clearing Price for that Capacity Zone shall be set at the greater of: (1) the sum of the price specified by the Capacity Zone Demand Curve at the amount of capacity equal to the total amount that is awarded a Capacity Supply Obligation in the import-constrained Capacity Zone, and the Capacity Clearing Price for the Rest-of-Pool Capacity Zone, or; (2) the highest price of any offer or bid for a resource in the Capacity Zone that is awarded a Capacity Supply Obligation, subject to the other provisions of this Section III.13.2.

If neither of the two conditions above are met in the round, then that Capacity Zone will be included in the next round of the Forward Capacity Auction.

(b) **Rest-of-Pool Capacity Zone**.

If the Total System Capacity at the End-of-Round Price, adjusted as necessary in accordance with Section III.13.2.6 (Capacity Rationing Rule), and adjusted to include the additional supply in the import-constrained Capacity Zone that may be cleared at a higher price, equals or is less than the amount of capacity determined by the System-Wide Capacity Demand Curve, then the Forward Capacity Auction for the Rest-of-Pool Capacity Zone is concluded and the Rest-of-Pool Capacity Zone will not be included in further rounds of the Forward Capacity Auction.

The Capacity Clearing Price for the Rest-of-Pool Capacity Zone shall be set at the highest price at which the Total System Capacity is less than or equal to the amount of capacity determined by the System-Wide Capacity Demand Curve, subject to the other provisions of this Section III.13.2.

If the Forward Capacity Auction for the Rest-of-Pool Capacity Zone is not concluded then the Rest-of-Pool Capacity Zone will be included in the next round of the Forward Capacity Auction, and the auctioneer shall publish the Total System Capacity at the End-of-Round Price, adjusted to include the additional supply in the import-constrained Capacity Zone that may be cleared at a higher price, less the amount of capacity determined by the System-Wide Capacity Demand Curve at the End-of-Round Price.

(c) **Export-Constrained Capacity Zones**.

For a Capacity Zone modeled as an export-constrained Capacity Zone, if all of the following conditions are met during the round:

(1) the aggregate supply curve for the export-constrained Capacity Zone, adjusted as necessary in accordance with Section III.13.2.6 (Capacity Rationing Rule), is equal to or less than the maximum amount of capacity determined by the Capacity Zone Demand Curve at a price of zero;

(2) in the case of a nested Capacity Zone, the Forward Capacity Auction is concluded for the Capacity Zone within which the nested Capacity Zone is located, and;

(3) the Forward Capacity Auction is concluded for the Rest-of-Pool Capacity Zone;

then the Forward Capacity Auction for that Capacity Zone is concluded and such Capacity Zone will not be included in further rounds of the Forward Capacity Auction.

The Capacity Clearing Price for an export-constrained Capacity Zone that is not a nested export-constrained Capacity Zone shall be set at the greater of:

(1) the sum of:

(i) the price specified by the Capacity Zone Demand Curve at the amount of capacity equal to the total amount that is awarded a Capacity Supply Obligation in that Capacity Zone; and

(ii) the Capacity Clearing Price for the Rest-of-Pool Capacity Zone.

or;

(2) the highest price of any offer or bid for a resource in the Capacity Zone that is awarded a Capacity Supply Obligation, and subject to the other provisions of this Section III.13.2.

The Capacity Clearing Price for a nested export-constrained Capacity Zone shall be set at the greater of:

(1) the sum of:

(i) the price specified by the Capacity Zone Demand Curve at the amount of capacity equal to the total amount that is awarded a Capacity Supply Obligation in that Capacity Zone; and

(ii) the Capacity Clearing Price for the Capacity Zone in which the nested Capacity Zone is located,

or;

(2) the highest price of any offer or bid for a resource in the Capacity Zone that is awarded a Capacity Supply Obligation, subject to the other provisions of this Section III.13.2.

If all of the conditions above are not satisfied in the round, then the auctioneer shall publish the quantity of excess supply in the export-constrained Capacity Zone at the End-of-Round Price (the amount of capacity offered at the End-of-Round Price in the export-constrained Capacity Zone minus the maximum amount of capacity determined by the Capacity Zone Demand Curve at a price of zero) and that Capacity Zone will be included in the next round of the Forward Capacity Auction.

(d) **Treatment of Import Capacity.** Where the amount of capacity offered from New Import Capacity Resources and Existing Import Capacity Resources over an interface between the New England Control Area and an external Control Area is less than or equal to that interface's approved capacity transfer limit (net of tie benefits, or net of HQICC in the case of the Phase I/II HVDC-TF), then the capacity offers from those resources shall be treated as capacity offers in the modeled Capacity Zone associated with that interface. Where the amount of capacity offered from New Import Capacity Resources and Existing Import Capacity Resources over an interface between the New England Control Area and an external Control Area is greater than that interface's approved capacity transfer limit (net of tie benefits, or net of HQICC in the case of the Phase I/II HVDC-TF), then the following provisions shall apply (separately for each such interface):

(i) For purposes of determining which capacity offers from the New Import Capacity Resources and Existing Import Capacity Resources over the interface shall clear and at what price, the offers over the interface shall be treated in the descending-clock auction as if they comprised a separately-modeled export-constrained capacity zone, with an aggregate supply curve consisting of the offers from the New Import Capacity Resources and Existing Import Capacity Resources over the interface.

(ii) The amount of capacity offered over the interface that will be included in the aggregate supply curve of the modeled Capacity Zone associated with the interface shall be the lesser of the following two quantities: the amount of capacity offered from New Import Capacity Resources

and Existing Import Capacity Resources over the interface; and the interface's approved capacity transfer limit (net of tie benefits, or net of HQICC in the case of the Phase I/II HVDC-TF).

(iii) The Forward Capacity Auction for New Import Capacity Resources and Existing Import Capacity Resources over the interface is concluded when the following two conditions are both satisfied: the amount of capacity offered from New Import Capacity Resource and Existing Import Capacity Resources over the interface is less than or equal to the interface's approved capacity transfer limit (net of tie benefits, or net of HQICC in the case of the Phase I/II HVDC-TF); and the Forward Capacity Auction is concluded in the modeled Capacity Zone associated with the interface.

(e) **Treatment of Export Capacity.** Any Export Bid or any Administrative Export De-List Bid that is used to export capacity through an export interface connected to an import-constrained Capacity Zone from another Capacity Zone, or through an export interface connected to the Rest-of-Pool Capacity Zone from an export-constrained Capacity Zone in the Forward Capacity Auction will be modeled in the Capacity Zone where the export interface that is identified in the Existing Capacity Qualification Package is located. The Export Bid or Administrative Export De-List Bid clears in the Capacity Zone where the Export Bid or Administrative Export De-List Bid is modeled.

(i) Then the MW quantity equal to the relevant Export Bid or Administrative Export De-List Bid from the resource associated with the Export Bid or Administrative Export De-List Bid will be de-listed in the Capacity Zone where the resource is located. If the export interface is connected to an import-constrained Capacity Zone, the MW quantity procured will be in addition to the amount of capacity determined by the Capacity Zone Demand Curve for the import-constrained Capacity Zone.

(ii) If the Export Bid or Administrative Export De-List Bid does not clear, then the resource associated with the Export Bid or Administrative Export De-List Bid will not be de-listed in the Capacity Zone where the resource is located.

III.13.2.3.4. Determination of Final Capacity Zones.

(a) For all Forward Capacity Auctions up to and including the sixth Forward Capacity Auction (for the Capacity Commitment Period beginning June 1, 2015), after the Forward Capacity Auction is concluded for all modeled Capacity Zones, the final set of distinct Capacity Zones that will be used for all

purposes associated with the relevant Capacity Commitment Period, including for the purposes of reconfiguration auctions and Capacity Supply Obligation Bilaterals, shall be those having distinct Capacity Clearing Prices as a result of constraints between modeled Capacity Zones binding in the running of the Forward Capacity Auction. Where a modeled constraint does not bind in the Forward Capacity Auction, and as a result adjacent modeled Capacity Zones clear at the same Capacity Clearing Price, those modeled Capacity Zones shall be a single Capacity Zone used for all purposes of the relevant Capacity Commitment Period, including for the purposes of reconfiguration auctions and Capacity Supply Obligation Bilaterals.

(b) For all Forward Capacity Auctions beginning with the seventh Forward Capacity Auction (for the Capacity Commitment Period beginning June 1, 2016) the final set of distinct Capacity Zones that will be used for all purposes associated with the relevant Capacity Commitment Period, including for the purposes of reconfiguration auctions and Capacity Supply Obligation Bilaterals, shall be those described in Section III.12.4.

III.13.2.4. Forward Capacity Auction Starting Price and the Cost of New Entry.

The Forward Capacity Auction Starting Price is max [1.6 multiplied by Net CONE, CONE]. References in this Section III.13 to the Forward Capacity Auction Starting Price shall mean the Forward Capacity Auction Starting Price for the Forward Capacity Auction associated with the relevant Capacity Commitment Period.

CONE for the Forward Capacity Auction for the Capacity Commitment Period beginning on June 1, 2021 is $11.35/kW-month.

Net CONE for the Forward Capacity Auction for the Capacity Commitment Period beginning on June 1, 2021 is $8.04/kW-month.

CONE and Net CONE shall be recalculated for the Capacity Commitment Period beginning on June 1, 2025 and no less often than once every three years thereafter. Whenever these values are recalculated, the ISO will review the results of the recalculation with stakeholders and the new values will be filed with the Commission prior to the Forward Capacity Auction in which the new value is to apply.

Between recalculations, CONE and Net CONE will be adjusted for each Forward Capacity Auction pursuant to Section III.A.21.1.2(e). Prior to applying the annual adjustment for the Capacity

Commitment Period beginning on June 1, 2019, Net CONE will be reduced by $0.43/kW-month to reflect the elimination of the PER adjustment. The adjusted CONE and Net CONE values will be published on the ISO's web site.

III.13.2.5. Treatment of Specific Offer and Bid Types in the Forward Capacity Auction.

III.13.2.5.1. Offers from New Generating Capacity Resources, New Import Capacity Resources, and New Demand Capacity Resources.

A New Capacity Offer (other than one from a Conditional Qualified New Resource) clears (receives a Capacity Supply Obligation for the associated Capacity Commitment Period) in the Forward Capacity Auction if the Capacity Clearing Price is greater than or equal to the price specified in the offer, except possibly as a result of the Capacity Rationing Rule described in Section III.13.2.6. An offer from a Conditional Qualified New Resource clears (receives a Capacity Supply Obligation for the associated Capacity Commitment Period) in the Forward Capacity Auction, except possibly as a result of the Capacity Rationing Rule described in Section III.13.2.6, if all of the following conditions are met: (i) the Capacity Clearing Price is greater than or equal to the price specified in the offer; (ii) capacity from that resource is considered in the determination of clearing as described in Section III.13.2.3.2(f); and (iii) such offer minimizes the costs for the associated Capacity Commitment Period, subject to Section III.13.2.7.7(c).

The amount of capacity that receives a Capacity Supply Obligation through the Forward Capacity Auction shall not exceed the quantity of capacity offered from the New Generating Capacity Resource, New Import Capacity Resource, or New Demand Capacity Resource at the Capacity Clearing Price.

III.13.2.5.2. Bids and Offers from Existing Generating Capacity Resources, Existing Import Capacity Resources, and Existing Demand Capacity Resources.

III.13.2.5.2.1. Permanent De-List Bids and Retirement De-List Bids.

(a) Except as provided in Section III.13.2.5.2.5, a Permanent De-List Bid, Retirement De-List Bid or Proxy De-List Bid clears in the Forward Capacity Auction (does not receive a Capacity Supply Obligation) if the Capacity Clearing Price is less than or equal to the price specified in the bid, except possibly as a result of the Capacity Rationing Rule described in Section III.13.2.6.

(b) Unless the capacity has been retained for reliability pursuant to Section III.13.2.5.2.5, if all or part of a resource with a Permanent De-List Bid or Retirement De-List Bid does not clear in the Forward Capacity Auction (receives a Capacity Supply Obligation), the Lead Market Participant shall enter the uncleared portion of the bid into the qualification process for the following Forward Capacity Auction as described in Section III.13.1.2.3.1.5.

(c) If the Capacity Clearing Price is greater than the price specified in a de-list bid submitted by a Lead Market Participant that elected conditional treatment for the de-list bid pursuant to Section III.13.1.2.4.1(b), and there is an associated Proxy De-List Bid that does not clear (receives a Capacity Supply Obligation), the resource will receive a Capacity Supply Obligation at the Capacity Clearing Price.

(d) The process by which the primary auction is cleared (but not the compilation of offers and bids pursuant to Sections III.13.2.3.1 and III.13.2.3.2) will be repeated after the substitution auction is completed if one of the following conditions is met: (1) if any Proxy De-List Bid entered as a result of a Lead Market Participant electing to retire pursuant to Section III.13.1.2.4.1(a) does not clear (receives a Capacity Supply Obligation) in the first run of the primary auction-clearing process and retains some portion of its Capacity Supply Obligation in the substitution auction; or (2) if any Proxy De-List Bid entered as a result of a Lead Market Participant electing conditional treatment pursuant to Section III.13.1.2.4.1(b) does not clear (receives a Capacity Supply Obligation) in the first run of the primary auction-clearing process, the de-list bid submitted by the Lead Market Participant is at or above the Capacity Clearing Price, and the Proxy De-List Bid retains some portion of its Capacity Supply Obligation in the substitution auction. The second run of the primary auction-clearing process: (i) excludes all Proxy De-List Bids, (ii) includes the offers and bids of resources compiled pursuant to Section III.13.2.3.2 that did not receive a Capacity Supply Obligation in the first run of the primary auction-clearing process, excluding the offers, or portion thereof, associated with resources that acquired a Capacity Supply Obligation in the substitution auction, and (iii) includes the capacity of resources, or portion thereof, that retain a Capacity Supply Obligation after the first run of the primary auction-clearing process and the substitution auction. The second run of the primary auction-clearing process shall not affect the Capacity Clearing Price of the Forward Capacity Auction (which is established by the first run of the primary auction-clearing process).

(e) Resources (other than those still subject to a multi-year Capacity Commitment Period election as described in Sections III.13.1.1.2.2.4 and III.13.1.4.1.1.2.7) that receive a Capacity Supply Obligation as a

result of the first run of the primary auction-clearing process shall be paid the Capacity Clearing Price during the associated Capacity Commitment Period. Where the second run of the primary auction-clearing process procures additional capacity, the resulting price, paid during the associated Capacity Commitment Period (and subsequent Capacity Commitment Periods, as elected pursuant to Section III.13.1.1.2.2.4 or Section III.13.1.4.1.1.2.7) to the additionally procured capacity, shall be equal to or greater than the adjusted price resulting from the first run of the primary auction-clearing process for that Capacity Zone.

III.13.2.5.2.2. Static De-List Bids and Export Bids.

Except as provided in Section III.13.2.5.2.5, a Static De-List Bid or an Export Bid clears in the Forward Capacity Auction (does not receive a Capacity Supply Obligation for the associated Capacity Commitment Period) if the Capacity Clearing Price is less than or equal to the price specified in the bid, except possibly as a result of the Capacity Rationing Rule described in Section III.13.2.6.

III.13.2.5.2.3. Dynamic De-List Bids.

A Dynamic De-List Bid clears in the Forward Capacity Auction (does not receive a Capacity Supply Obligation for the associated Capacity Commitment Period) if the Capacity Clearing Price is less than or equal to the price specified in the bid, except possibly as a result of the Capacity Rationing Rule described in Section III.13.2.6. If more Dynamic De-List Bids are submitted at a price than are needed to clear the market, such Dynamic De-List Bids shall be cleared pro-rata, but in no case less than a resource's Rationing Minimum Limit.

III.13.2.5.2.4. Administrative Export De-List Bids.

An Administrative Export De-List Bid clears in the Forward Capacity Auction (does not receive a Capacity Supply Obligation for the associated Capacity Commitment Period) regardless of the Capacity Clearing Price.

III.13.2.5.2.5. Reliability Review.

The ISO shall review each Retirement De-List Bid, Permanent De-List Bid, Static De-List Bid, Export Bid, Administrative Export De-List Bid, Dynamic De-List Bid, and substitution auction demand bid to determine whether the capacity associated with that bid is needed for reliability reasons during the Capacity Commitment Period associated with the Forward Capacity Auction; Proxy De-List Bids shall not be reviewed.

(a) The reliability review of de-list bids will be conducted in descending price order using the price as finalized during qualification or as otherwise directed by the Commission. De-list bids with the same price will be reviewed in the order that produces the least negative impact to reliability; where bids are the same price and provide the same impact to reliability, they will be reviewed based on their submission time. If de-list bids with the same price are from a single generating station, they will be reviewed in an order that seeks to provide (1) the least-cost solution under Section III.13.2.5.2.5.1(d) and (2) the minimum aggregate quantity required for reliability from the generating station. The reliability review of substitution auction demand bids that would otherwise clear will be conducted in order beginning with the resource whose cleared bids contribute the greatest amount to social surplus. The capacity associated with a bid shall be deemed needed for reliability reasons if the absence of the capacity would result in the violation of any NERC or NPCC criteria, or ISO New England System Rules. Bids shall only be rejected pursuant to this Section III.13.2.5.2.5 for the sole purpose of addressing a local reliability issue, and shall not be rejected solely on the basis that acceptance of the bid may result in the procurement of less capacity than the Installed Capacity Requirement (net of HQICCs) or the Local Sourcing Requirement for a Capacity Zone.

(b) If a Retirement De-List Bid, Permanent De-List Bid, Static De-List Bid, Export Bid, Administrative Export De-List Bid, or Dynamic De-List Bid would otherwise clear in the Forward Capacity Auction, but the ISO has determined that some or all of the capacity associated with the de-list bid is needed for reliability reasons, then the de-list bid having capacity needed for reliability will not clear in the Forward Capacity Auction. If the ISO has determined that some or all of the capacity associated with a substitution auction demand bid that would otherwise clear is needed for reliability reasons, then the entire demand bid will not be further included in the substitution auction.

(c) The Lead Market Participant shall be notified that its bid did not clear for reliability reasons at the later of: (i) immediately after the end of the Forward Capacity Auction round in which the auction price reaches the price of the de-list bid; or (ii) as soon as practicable after the time at which the ISO has determined that the bid must be rejected for reliability reasons. In no event, however, shall a Lead Market Participant be notified that a bid submitted pursuant to Section III.13.1.2.5 and accepted in the qualification process for an Existing Generating Capacity Resource did not clear for reliability reasons if the associated New Generating Capacity Resource remains in the Forward Capacity Auction. In such a case, the Lead Market Participant shall be notified that its bid did not clear for reliability reasons at the later of: (i) immediately after the end of the Forward Capacity Auction round in which the auction price reaches the price of the bid; (ii) immediately after the end of the Forward Capacity Auction round in

which the associated New Generating Capacity Resource is fully withdrawn (that is, the Forward Capacity Auction reaches a price at which the resource's New Capacity Offer is zero capacity); or (iii) as soon as practicable after the time at which the ISO has determined that the bid must be rejected for reliability reasons.

(d) A resource that has a de-list bid rejected for reliability reasons shall be compensated pursuant to the terms set out in Section III.13.2.5.2.5.1 and shall have a Capacity Supply Obligation as described in Section III.13.6.1.

(e) The ISO shall review the results of each annual reconfiguration auction and determine whether the reliability need which caused the ISO to reject the de-list bid has been met through the annual reconfiguration auction. The ISO may also attempt to address the reliability concern through other reasonable means (including transmission enhancements).

(f) If the reliability need that caused the ISO to reject a de-list bid is met through a reconfiguration auction or other means, the resource shall retain its Capacity Supply Obligation through the end of the Capacity Commitment Period for which it was retained for reliability (provided that resources that have Permanent De-List Bids or Retirement De-List Bids rejected for reliability shall be permanently de-listed or retired as of the first day of the subsequent Capacity Commitment Period (or earlier if the resource sheds the entirety of the Capacity Supply Obligation as described in Section III.13.2.5.2.5.3(a)(ii) or Section III.13.2.5.2.5.3(b)(ii))).

(g) If a Permanent De-List Bid or a Retirement De-List Bid is rejected for reliability reasons, and the reliability need is not met through a reconfiguration auction or other means, that resource, or portion thereof, as applicable, is no longer eligible to participate as an Existing Capacity Resource in any reconfiguration auction, Forward Capacity Auction or Capacity Supply Obligation Bilateral for that and subsequent Capacity Commitment Periods. If the resource, or portion thereof, continues to be needed for reliability reasons, it shall be counted as capacity in the Forward Capacity Auction and shall be compensated as described in Section III.13.2.5.2.5.1.

(h) The ISO shall review with the Reliability Committee (i) the status of any prior rejected de-list bids reported to the Commission in an FCA results filing pursuant to Section 13.8.2, and (ii) the status of any Retirement De-List Bid or Permanent De-List Bid that has been rejected for reliability reasons and

has elected to continue to operate, prior to the New Capacity Qualification Deadline in accordance with Section 4.1(c) of Attachment K of the ISO OATT.

If an identified reliability need results in the rejection of a Retirement De-List Bid, Permanent De-List Bid, Export Bid, Administrative Export De-List Bid, Static De-List Bid, or Dynamic De-List Bid while executing an FCA, the ISO shall (i) review each specific reliability need with the Reliability Committee in accordance with the timing provided for in the ISO New England Operating Documents and, (ii) update the current system Needs Assessments pursuant to Section 4.1(c) of Attachment K of the ISO OATT. This review and update will follow ISO's filing of the FCA results with the Commission pursuant to Section 13.8.2.

III.13.2.5.2.5A Fuel Security Reliability Review

(a) This Section III.13.2.5.2.5A will remain in effect for the 2022/23 and 2023/24 Capacity Commitment Periods, after which this Section III.13.2.5.2.5A will sunset.

(b) This Section III.13.2.5.2.5A will apply to (i) Retirement De-List Bids, (ii) substitution auction demand bids, and (iii) bilateral transactions and reconfiguration auctions demand bids submitted by an Existing Generating Capacity Resource that has been identified as being needed for fuel security during a Forward Capacity Auction. Terms set out in this Section III.13.2.5.2.5A will apply only for the period and resources described within this Section III.13.2.5.2.5A. Where the terms and conditions in this Section III.13.2.5.2.5A differ from terms otherwise set out in Section III.13, the terms of this Section III.13.2.5.2.5A will control for the period and circumstances described in Section III.13.2.5.2.5A.

(c) A fuel security reliability review for the Forward Capacity Market will be performed pursuant to Appendix L to Section III of the Tariff, and in accordance with the inputs and methodology set out to establish the fuel security reliability standard in Appendix I of Planning Procedure No. 10.

(d) For fuel security reliability reviews performed for the primary Forward Capacity Auction, the fuel security reliability review will be performed after the Existing Capacity Retirement Deadline and conducted in descending price order using the price as submitted in the Retirement De-List Bids. Bids with the same price will be reviewed in the order that produces the least negative impact to reliability. Where multiple bids have the same price and the retirement of the Existing Generating Capacity Resources would have the same impact to reliability, they will be reviewed based on their submission

time. If bids with the same price are from a single generating station, they will be reviewed in an order that seeks to provide (1) the least-cost solution under Section III.13.2.5.2.5.1(d), and (2) the minimum aggregate quantity required for reliability from the generating station. An Existing Generating Capacity Resource may be needed for both fuel security and for transmission security pursuant to Section III.13.2.5.2.5. The fuel security reliability review will be performed in advance of the reliability review for transmission security. Where an Existing Generating Capacity Resource is needed for both fuel security reasons pursuant to this Section III.13.2.5.2.5A, and transmission security reliability reasons pursuant to Section III.13.2.5.2.5, the generator will be retained for fuel security for purposes of cost allocation.

(e) If an Existing Generating Capacity Resource is identified as being needed for fuel security reasons, and the reliability need is not met through a reconfiguration auction or other means, that resource, or portion thereof, as applicable may not participate in Annual Reconfiguration Auctions for the Capacity Commitment Period(s) for which it is needed for fuel security, or earlier 2022/23 and 2023/24 Capacity Commitment Periods. Such an Existing Generating Capacity Resource that is identified as being needed for fuel security may participate in monthly bilateral transactions and monthly reconfiguration auctions, but may not submit monthly bilateral transactions for December, January or February, or demand bids for the December, January, or February monthly reconfiguration auctions for any period for which they have been identified as being needed for fuel security.

(f) Participants that have submitted a Retirement De-List Bid will be notified by ISO New England if their resource is needed for fuel security reliability reasons no later than 90 days after the Existing Capacity Retirement Deadline. Participants that have submitted a substitution auction demand bid, and where the demand bid has been rejected for reliability reasons, will be notified after the relevant Forward Capacity Auction has been completed.

(g) Where a Retirement De-List Bid would otherwise clear in the Forward Capacity Auction, but the ISO has determined that some or all of the capacity associated with the de-list bid is needed for fuel security reliability reasons, the provisions of III.13.2.5.2.5(b) shall apply.

(h) Existing Generating Capacity Resources that have had their Retirement De-list Bid rejected for fuel security reliability reasons and that do not elect to unconditionally or conditionally retire shall be eligible for compensation pursuant to Section III.13.2.5.2.5.1, except that the difference between payments based on resource de-list bids or cost-of-service compensation as detailed in Section III.13.2.5.2.5.1 and

payments based on the Capacity Clearing Price for the Forward Capacity Market under this Section III.13.2.5.2.5.1 shall be allocated on a regional basis to Real Time Load Obligation, excluding Real-Time Load Obligation associated with Dispatchable Asset Related Demand Resources (DARD Pumps and other electric storage based DARDs) and Real-Time Load Obligation associated with Coordinated External Transactions, allocated and collected over a 12 month period. Resources that that are identified as needed for fuel security reliability reasons will have their capacity entered into the Forward Capacity Auction pursuant to III.13.2.5.2.5(g) and III.13.2.3.2(b).

(i) Where an Existing Generating Capacity Resource elects a cost-of-service agreement pursuant to Section III.13.2.5.2.5.1 to address a fuel security reliability need, the term of such a cost-of-service agreement may not exceed two years, including renewal through evergreen provisions.

(j) The ISO shall perform an annual reevaluation of any Existing Generating Capacity Resources retained for reliability under this provision. If a resource associated with a Retirement De-List Bid that was rejected for reliability reasons pursuant to this section, is found to no longer be needed for fuel security, and is not needed for another reliability reason pursuant to Section III.13.2.5.2.5, the resource will be retired from the system as described in Section III.13.2.5.2.5.3(a)(1). In no case will a resource retained for fuel security be retained for fuel security beyond June 1, 2024.

(k) The ISO will review Retirement De-List Bids rejected for fuel security reliability reasons with the Reliability Committee in the same manner as described in Section III.13.2.5.2.5(h).

III.13.2.5.2.5.1. Compensation for Bids Rejected for Reliability Reasons.

(a) In cases where a Static De-List Bid, Export Bid, Administrative Export De-List Bid, Dynamic De-List Bid, partial Permanent De-List Bid, or partial Retirement De-List Bid has been rejected for reliability reasons pursuant to Sections III.13.1.2.3.1.5.1 or III.13.2.5.2.5, the resource will be paid by the ISO in the same manner as all other capacity resources, except that payment shall be made on the basis of its de-list bid as accepted for the Forward Capacity Auction for the relevant Capacity Commitment Period instead of the Forward Capacity Market Clearing Price. Under this Section, accepted Dynamic De-List Bids filed with the Commission as part of the FCA results filing are subject to review and approval by the Commission pursuant to the “just and reasonable” standard of Section 205 of the Federal Power Act. If a resource with a partial Permanent De-List Bid or partial Retirement De-List Bid continues to be needed for reliability in Capacity Commitment Periods following the Capacity Commitment Period for which the partial Permanent De-List Bid or partial Retirement De-List Bid was rejected, payment will continue to be pursuant to this Section III.13.2.5.2.5.1(a).

(b) In cases where a Permanent De-List Bid or a Retirement De-List Bid for the capacity of an entire resource has been rejected for reliability reasons pursuant to Section III.13.1.2.3.1.5.1 or III.13.2.5.2.5, the resource will be paid either (i) in the same manner as all other capacity resources, except that payment shall be made on the basis of its Commission-approved Permanent De-List Bid or Commission-approved Retirement De-List Bid for the relevant Capacity Commitment Period instead of the Forward Capacity Market Clearing Price or (ii) under the terms of a cost-of-service agreement pursuant to Section III, Appendix I. Resources must notify the ISO of their election within six months after the ISO files the results of the relevant Forward Capacity Auction with the Commission. A resource that has had a Permanent De-List Bid or Retirement De-List Bid rejected for reliability reasons and does not notify the ISO of its election as described in this paragraph will be paid on the basis of the resource's Commission-approved Permanent De-List Bid or Commission-approved Retirement De-List Bid. Cost-of-service agreements must be filed with and approved by the Commission, and cost-of-service compensation may not commence until the Commission has approved the use of cost-of-service rates for the unit in question or has accepted the use of the cost-of-service rates subject to refund while the rate is reviewed. In no event will payment under the cost-of-service agreement start prior to the start of the relevant Capacity Commitment Period for which the Permanent De-List Bid or Retirement De-List Bid was submitted. If a resource continues to be needed for reliability in Capacity Commitment Periods following the Capacity Commitment Period for which the Permanent De-List Bid or Retirement De-List Bid was rejected, payment will continue to be pursuant to this Section III.13.2.5.2.5.1(b). Resources that elect payment based on the Commission-approved Permanent De-List Bid or Commission-approved Retirement De-List Bid may file with the Commission pursuant to Section 205 of the Federal Power Act to update its Permanent De-List Bid or Retirement De-List Bid if the unit is retained for reliability for a period longer than the Capacity Commitment Period for which the Permanent De-List Bid or Retirement De-List Bid was originally submitted.

(c) The difference between payments based on resource de-list bids or cost-of-service compensation as detailed in this Section III.13.2.5.2.5.1 and payments based on the market clearing price for the Forward Capacity Market under this Section III.13.2.5.2.5.1 shall be allocated to Regional Network Load within the affected Reliability Region.

(d) **Compensation for Existing Generating Capacity Resources at Stations with Common Costs that are Retained for Reliability**. If a Static De-List Bid, Permanent De-List Bid, or Retirement De-List Bid from an Existing Generating Capacity Resource that is associated with a Station having Common Costs is rejected for reliability reasons, the Existing Generating Capacity Resource will be paid as follows: (i) if one or more Existing Generating Capacity Resources at the Station assume a Capacity Supply Obligation through the normal clearing of the Forward Capacity Auction and one or more Existing Generating Capacity Resources are retained for reliability, then the Existing Generating Capacity Resources retained for reliability will be paid the sum of the Asset-Specific Going Forward Costs for the assets comprising that Existing Generating Capacity Resource; or (ii) if no Existing Generating Capacity Resources at the Station assumes a Capacity Supply Obligation through the normal clearing of the Forward Capacity Auction and one or more Existing Generating Capacity Resources are retained for reliability, then each Existing Generating Capacity Resource retained for reliability will be paid the sum of the Asset-Specific Going Forward Costs for the assets associated with that Existing Generating Capacity Resource plus a portion of the Station Going Forward Common Costs (such that the full amount of Station Going Forward Common Costs are allocated to the Existing Generating Capacity Resources retained for reliability).

(e) If ISO-NE is a party to a cost-of-service agreement filed after January 1, 2019 that changes any resource performance-related obligations contained in Section III, Appendix I (provided that those obligations are different than the obligations of an Existing Generating Capacity Resource with a Capacity Supply Obligation), no later than 30 days after such agreement is filed with the Commission, ISO-NE shall provide to stakeholders quantitative and qualitative information on the need for, and the impacts of, the proposed changes.

III.13.2.5.2.5.2. Incremental Cost of Reliability Service From Permanent De-List Bid or Retirement De-List Bid Resources.

In cases where an Existing Generating Capacity Resource or Existing Demand Capacity Resource has had a Permanent De-List Bid or Retirement De-List Bid for the entire resource rejected for reliability reasons pursuant to Sections III.13.1.2.3.1.5.1 or III.13.2.5.2.5, does not elect to retire pursuant to Section III.13.1.2.3.1.5.1(d), and must make a capital improvement to the unit to remain in operation in order to continue to operate to meet the reliability need identified by the ISO, the resource may make application to the Commission pursuant to Section 205 of the Federal Power Act to receive just and reasonable compensation of the capital investment pursuant to the following:

(a) **Notice to State Utility Commissions, the ISO and Stakeholder Committees of Expectation that a Capital Expense will be Necessary to Meet the Reliability Need Identified by the ISO**: A resource seeking to avail itself of the recovery mechanism provided in this Section must notify the state utility commissions in the states where rate payers will fund the capital improvement, the ISO, and the Participants Committee of its intent to make the capital expenditure and the need for the expenditure. This notification must be made at least 120 days prior to the resource making the capital expenditure.

(b) **Required Showing Made to the Federal Energy Regulatory Commission**: In order to receive just and reasonable compensation for a capital expenditure under this Section, a resource must file an explanation of need with the Commission that explains why the capital expenditure is necessary in order to meet the reliability need identified by the ISO. This showing must demonstrate that the expenditure is reasonably determined to be the least-cost commercially reasonable option consistent with Good Utility Practice to meet the reliability need identified by the ISO. If the resource elects cost-of-service treatment pursuant to Section III.13.2.5.2.5.1(b), the Incremental Cost of Reliability Service filing described in this Section must be made separately from and may be made in advance of the resource's cost-of-service filing.

(c) **Allocation:** Costs of capital expenditures approved by the Commission under this provision shall be allocated to Regional Network Load within the affected Reliability Region.

III.13.2.5.2.5.3. Retirement and Permanent De-Listing of Resources.

(a)(i) A resource, or portion thereof, will be retired coincident with the commencement of the relevant Capacity Commitment Period, or earlier as described in Section III.13.2.5.2.5.3(a)(ii), if the resource: (1) submitted a Retirement De-List Bid at or above the Forward Capacity Auction Starting Price and was not retained for reliability pursuant to Section III.13.1.2.3.1.5.1; (2) submitted a Permanent De-List Bid or Retirement De-List Bid, elected to retire pursuant to Section III.13.1.2.4.1(a), and was not retained for reliability pursuant to Section III.13.1.2.3.1.5.1; (3) elected conditional treatment pursuant to Section III.13.1.2.4.1(b) for a Retirement De-List Bid with a submitted price at or above the Capacity Clearing Price and was not retained for reliability pursuant to Section III.13.1.2.3.1.5.1; or (4) had a Commission-approved Retirement De-List Bid clear in the Forward Capacity Auction. In the case of a Retirement De-List Bid rejected for reliability, if the reliability need that resulted in the rejection for reliability is met, the resource, or portion thereof, will be retired coincident with the end of Capacity Supply Obligation (or earlier as described in Section III.13.2.5.2.5.3(a)(ii)) unless the Commission directs that the obligation to retire be removed or the retirement date extended as part of an Incremental Cost of Reliability Service

filing made pursuant to Section III.13.2.5.2.5.2. The interconnection rights, or relevant portion thereof, for the resource will terminate and the status of the resource, or portion thereof, will be converted to retired on the date of retirement, consistent with the provisions of Schedules 22 and 23 of the OATT.

(a)(ii) A resource, or portion thereof, that is to be retired pursuant to Section III.13.2.5.2.5.3(a)(i) may retire the resource, or portion thereof, earlier than the Capacity Commitment Period for which its Retirement De-List Bid was submitted if it is able to transfer the relevant Capacity Supply Obligation of the resource to another resource through one or more approved Capacity Supply Obligation Bilateral transactions as described in Section III.13.5.1 or reconfiguration auctions as described in Section III.13.4.1. A resource, or portion thereof, electing to retire pursuant to this provision must notify the ISO in writing of its election to retire and the date of retirement. The interconnection rights, or relevant portion thereof, for the resource will terminate and the status of the resource, or portion thereof, will be converted to retired on the date of retirement, consistent with the provisions of Schedules 22 and 23 of the OATT.

(b)(i) A resource, or portion thereof, will be permanently de-listed from the Forward Capacity Market as of the relevant Capacity Commitment Period, or earlier as described in Section III.13.2.5.2.5.3(b)(ii), if the resource: (1) submitted an Internal Market Monitor-approved Permanent De-List Bid at or above the Forward Capacity Auction Starting Price and was not retained for reliablity pursuant to Section III.13.1.2.3.1.5.1; (2) elected conditional treatment pursuant to Section III.13.1.2.4.1(b) for a Permanent De-List Bid with a submitted price at or above the Capacity Clearing Price and was not retained for reliability pursuant to Section III.13.1.2.3.1.5.1; or (3) had a Commission-approved Permanent De-List Bid clear in the Forward Capacity Auction. The CNR Capability interconnection rights, or relevant portion thereof, for the resource will be adjusted downward to reflect the Permanent De-List Bid, consistent with the provisions of Schedules 22 and 23 of the OATT. A resource that permanently de-lists pursuant to this Section III.13.2.5.2.5.3(b)(i) is precluded from subsequent participation in the Forward Capacity Market unless it qualifies as a New Generating Capacity Resource pursuant to Section III.13.1.1.1.2.

(b)(ii) A resource, or portion thereof, that is to be permanently de-listed pursuant to Section III.13.2.5.2.5.3(b)(i) may be permanently de-listed earlier than the Capacity Commitment Period for which its Permanent De-List Bid was submitted if it is able to transfer the entire Capacity Supply Obligation of the resource to another resource through one or more approved Capacity Supply Obligation Bilateral transactions as described in Section III.13.5.1 or reconfiguration auctions as described in Section III.13.4.

(c) A resource that has never been counted as a capacity resource may retire the asset by notifying the ISO in writing of its election to retire and the date of retirement. The date specified for retirement is subject to the limit for resource inactivity set out in Section III.13.2.5.2.5.3(d). The interconnection rights for the resource will terminate and the status of the resource will be converted to retired on the date of retirement.

(d) A resource that does not operate commercially for a period of three calendar years will be deemed by the ISO to be retired. The interconnection rights for the unit will terminate and the status of the unit will be converted to retired on the date of retirement. Where a generator has submitted an application to repower under Schedule 22 or 23 of the OATT, the current interconnection space will be maintained beyond the three years unless the application under Schedule 22 or 23 is withdrawn voluntarily or by the operation of those provisions. Where an application is withdrawn under Schedule 22 or 23, the three year period will be calculated from the last day of commercial operation of the resource.

III.13.2.6. Capacity Rationing Rule.

Except for Dynamic De-List Bids, Export Bids, and offers from New Import Capacity Resources that are subject to rationing pursuant to Section III.13.1.3.5.8 and Existing Import Capacity Resources that are subject to rationing pursuant to Section III.13.1.3.3.A, offers and bids in the Forward Capacity Auction must clear or not clear in whole, unless the offer or bid specifically indicates that it may be rationed. A resource may elect to be rationed to its Rationing Minimum Limit pursuant to Sections III.13.1.1.2.2.3 and III.13.1.2.1.2. Offers from New Import Capacity Resources and Existing Import Capacity Resources will not be rationed where such rationing would violate any applicable physical minimum flow requirements on the associated interface. Export Bids may elect to be rationed generally, but regardless of such election will always be subject to potential rationing where the associated external interface binds. If more Dynamic De-List Bids are submitted at a price than are needed to clear the market, the bids shall be cleared pro-rata, subject to honoring the Rationing Minimum Limit of the resources. Where an offer or bid may be rationed, such rationing may not result in procuring an amount of capacity that is below the associated resource's Rationing Minimum Limit.

III.13.2.7. Determination of Capacity Clearing Prices.

The Capacity Clearing Price in each Capacity Zone shall be the price established by the descending clock auction as described in Section III.13.2.3, subject to the other provisions of this Section III.13.2.7. The Capacity Clearing Price for the Rest-of-Pool Capacity Zone and the Capacity Clearing Price for each

import-constrained Capacity Zone shall not exceed the Forward Capacity Auction Starting Price. The Capacity Clearing Price for an export-constrained Capacity Zone shall not be less than zero.

III.13.2.7.1. Import-Constrained Capacity Zone Capacity Clearing Price Floor.
The Capacity Clearing Price in an import-constrained Capacity Zone shall not be lower than the Capacity Clearing Price in the Rest-of-Pool Capacity Zone. If after the Forward Capacity Auction is conducted, the Capacity Clearing Price in an import-constrained Capacity Zone is less than the Capacity Clearing Price in the Rest-of-Pool Capacity Zone, all resources clearing in the import-constrained Capacity Zone shall be paid based on the Capacity Clearing Price in the Rest-of-Pool Capacity Zone during the associated Capacity Commitment Period.

III.13.2.7.2. Export-Constrained Capacity Zone Capacity Clearing Price Ceiling.
The Capacity Clearing Price in an export-constrained Capacity Zone shall not be higher than the Capacity Clearing Price in the Rest-of-Pool Capacity Zone.

The Capacity Clearing Price in a nested Capacity Zone shall not be higher than the Capacity Clearing Price in the Capacity Zone within which it is located.

III.13.2.7.3. [Reserved.]

III.13.2.7.3A. Treatment of Imports.
At the Capacity Clearing Price, if the amount of capacity offered from New Import Capacity Resources and Existing Import Capacity Resources over an interface between an external Control Area and the New England Control Area is greater than that interface's approved capacity transfer limit (net of tie benefits, or net of HQICC in the case of the Phase I/II HVDC-TF):

(a) the full amount of capacity offered at that price from Existing Import Capacity Resources associated with contracts listed in Section III.13.1.3.3.A(c) shall clear, unless that amount of capacity is greater than the interface's approved capacity transfer limit (net of tie benefits, or net of HQICC in the case of the Phase I/II HVDC-TF), in which case the capacity offered at that price from Existing Import Capacity Resources associated with contracts listed in Section III.13.1.3.3.A(c) shall be rationed such that the interface's approved capacity transfer limit (net of tie benefits, or net of HQICC in the case of the Phase I/II HVDC-TF) is not exceeded; and

(b) if there is space remaining over the interface after the allocation described in subsection (a) above, then the capacity offered at that price from New Import Capacity Resources and Existing Import Capacity Resources other than Existing Import Capacity Resources associated with the contracts listed in Section III.13.1.3.3.A(c) will be rationed such that the interface's approved capacity transfer limit (net of tie benefits, or net of HQICC in the case of the Phase I/II HVDC-TF) is not exceeded. If the capacity offered at that price by any single New Import Capacity Resource or Existing Import Capacity Resource that is not associated with the contracts listed in Section III.13.1.3.3.A(c) is greater than the interface's approved capacity transfer limit (net of tie benefits, or net of HQICC in the case of the Phase I/II HVDC-TF), then the capacity offered by that resource that is above the interface's approved capacity transfer limit (net of tie benefits, or net of HQICC in the case of the Phase I/II HVDC-TF) shall not be included in the rationing.

III.13.2.7.4. Effect of Capacity Rationing Rule on Capacity Clearing Price.

Where the requirement that offers and bids clear or not clear in whole (Section III.13.2.6) prohibits the descending clock auction in its normal progression from clearing one or more Capacity Zones at the precise amount of capacity determined by the Capacity Zone Demand Curves specified in Section III.13.2.2, then the auctioneer shall analyze the aggregate supply curve to determine cleared capacity offers and Capacity Clearing Prices that seek to maximize social surplus for the associated Capacity Commitment Period. The clearing algorithm may result in offers below the Capacity Clearing Price not clearing, and in de-list bids below the Capacity Clearing Price clearing.

III.13.2.7.5. Effect of Decremental Repowerings on the Capacity Clearing Price.

Where the effect of accounting for certain repowering offers and bids (as described in Section III.13.2.3.2(e)) results in the auction not clearing at the lowest price for the required quantity of capacity, then the auctioneer will conduct additional auction rounds of the Forward Capacity Auction as necessary to minimize capacity costs.

III.13.2.7.6. Minimum Capacity Award.

Each offer (excluding offers from Conditional Qualified New Resources that do not satisfy the conditions specified in Sections III.13.2.5.1(i)-(iii)) clearing in the Forward Capacity Auction shall be awarded a Capacity Supply Obligation at least as great as the amount of capacity offered at the End-of-Round Price in the final round of the Forward Capacity Auction. For Intermittent Power Resources, the Capacity

Supply Obligation for months in the winter period (as described in Section III.13.1.5) shall be adjusted based on its winter Qualified Capacity as determined pursuant to Section III.13.1.1.2.2.6 and Section III.13.1.2.2.2.

III.13.2.7.7. Tie-Breaking Rules.

Where the provisions in this Section III.13.2 for clearing the Forward Capacity Auction (system-wide or in a single Capacity Zone) result in a tie – that is, where two or more resources offer sufficient capacity at prices that would clear the auction at the same minimum costs – the auctioneer shall apply the following rules (in sequence, as necessary) to determine clearing:

(a) [Reserved.]

(b) If multiple projects may be rationed, they will be rationed proportionately.

(c) Where clearing either the offer associated with a resource with a higher queue priority at a Conditional Qualified New Resource's location or the offer associated with the Conditional Qualified New Resource would result in equal costs, the offer associated with the resource with the higher queue priority shall clear.

(d) The offer associated with the Project Sponsor having the lower market share in the capacity auction (including Existing Generating Capacity Resources, Existing Import Capacity Resources, and Existing Demand Capacity Resources) shall be cleared.

III.13.2.8. Capacity Substitution Auctions.

III.13.2.8.1. Administration of Substitution Auctions.

Following the completion of the primary auction-clearing process of the Forward Capacity Auction as provided for in Section III.13.2, the ISO shall conduct a substitution auction, using a static double auction to clear supply offers (offers to assume a Capacity Supply Obligation) and demand bids (bids to shed a Capacity Supply Obligation). Supply offers and demand bids will be modeled in the Capacity Zone where the associated resources are electrically interconnected.

III.13.2.8.1.1. Substitution Auction Clearing and Awards.

The substitution auction shall maximize total social surplus as specified by the demand bids and supply offers used in the auction. The maximization is constrained as follows:

(i) By the external interface limits modeled in the primary auction-clearing process.

(ii) Such that the net cleared Capacity Supply Obligations (total acquired less total shed) in the substitution auction is equal to zero.

(iii) Such that, for each import-constrained Capacity Zone, if the zone's total Capacity Supply Obligations awarded in the primary auction-clearing process of the Forward Capacity Auction is less than the zone threshold quantity specified below, then the zone's net cleared Capacity Supply Obligations (total acquired less total shed) in the substitution auction is equal to zero; otherwise, the sum of the zone's total Capacity Supply Obligations awarded in the primary auction-clearing process and the zone's net cleared Capacity Supply Obligations (total acquired less total shed) in the substitution auction is greater than or equal to the zone threshold quantity specified below.

(iv) Such that, for each export-constrained Capacity Zone, if the zone's total Capacity Supply Obligations awarded in the primary auction-clearing process of the Forward Capacity Auction is greater than the zone threshold quantity specified below, then the zone's net cleared Capacity Supply Obligations (total acquired less total shed) in the substitution auction is equal to zero; otherwise, the sum of the zone's total Capacity Supply Obligations awarded in the primary auction-clearing process and the zone's net cleared Capacity Supply Obligations (total acquired less total shed) in the substitution auction is less than or equal to the zone threshold quantity specified below.

In applying constraint (iii), the zone threshold quantity for an import-constrained Capacity Zone shall be equal to the sum of its Capacity Zone Demand Curve truncation point quantity specified in Section III.13.2.2.2 and the total quantity of any Export Bids and any Administrative Export De-List Bids for which the exporting resource is located outside the import-constrained Capacity Zone, that are used to export capacity across an external interface connected to the import-constrained Capacity Zone, and that cleared in the primary auction-clearing process of the Forward Capacity Auction.

In applying constraint (iv), the zone threshold quantity for an export-constrained Capacity Zone shall be equal to its Capacity Zone Demand Curve truncation point quantity specified in Section III.13.2.2.3 less the total quantity of any Export Bids and any Administrative Export De-List Bids for which the exporting resource is located in the export-constrained Capacity Zone, including any Export Bids and any Administrative Export De-List Bids in an associated nested export-constrained Capacity Zone, that are

used to export capacity across an external interface connected to another Capacity Zone, and that cleared in the primary auction-clearing process of the Forward Capacity Auction.

In applying constraints (iii) and (iv), a zone's total Capacity Supply Obligations awarded in the primary auction-clearing process of the Forward Capacity Auction and net cleared Capacity Supply Obligations (total acquired less total shed) in the substitution auction shall include the Capacity Supply Obligations of Import Capacity Resources at each external interface connected to the Capacity Zone.

In applying constraints (iii) and (iv), a zone's total Capacity Supply Obligations awarded in the primary auction-clearing process of the Forward Capacity Auction shall include the Capacity Supply Obligations awarded to Proxy De-List Bids within the zone, and the zone's net cleared Capacity Supply Obligations (total acquired less total shed) in the substitution auction shall include the Capacity Supply Obligations shed from demand bids associated with Proxy De-List Bids within the zone.

In cases in which there are multiple clearing outcomes that would each maximize the substitution auction's objective, the following tie-breaking rules will apply in the following sequence: (i) non-rationable demand bids associated with Lead Market Participants having the largest total FCA Qualified Capacity of Existing Capacity Resources will be cleared first; and (ii) rationable supply offers will be cleared in proportion to their offer quantity.

For Intermittent Power Resources, other than those participating as the summer resource in a Composite FCM Transaction, the cleared award for supply offers and demand bids shall be adjusted for the months in the winter period (as described in Section III.13.1.5) using the ratio of the resource's cleared offer or bid amount divided by its FCA Qualified Capacity multiplied by its winter Qualified Capacity as determined pursuant to Section III.13.1.1.2.2.6 and Section III.13.1.2.2.2 after removing any portion of the resource's winter Qualified Capacity that is participating in a Composite FCM Transaction.

The cleared offer amount awarded to a Composite FCM Transaction in the substitution auction will be assigned to the summer and winter resources for their respective obligation months during the Capacity Commitment Period as described in Section III.13.1.5.

If, after the substitution auction, a resource has a Capacity Supply Obligation below its Economic Minimum Limit, it must meet the requirements of Section III.13.6.1.1.1.

III.13.2.8.1.2. Substitution Auction Pricing.

The substitution auction will specify clearing prices for Capacity Zones and external interfaces as follows.

For each import-constrained Capacity Zone, if the sum of the zone's total Capacity Supply Obligations awarded in the primary auction-clearing process of the Forward Capacity Auction and the zone's net cleared Capacity Supply Obligations (total acquired less total shed) in the substitution auction is greater than its zone threshold quantity specified in Section III.13.2.8.1.1, then supply offers and demand bids in the substitution auction in the import-constrained Capacity Zone shall be treated as offers and bids in the Rest-of-Pool Capacity Zone for purposes of determining substitution auction clearing prices.

For each export-constrained Capacity Zone,

(i) if the sum of the zone's total Capacity Supply Obligations, including Capacity Supply Obligations in a nested Capacity Zone, awarded in the primary auction-clearing process of the Forward Capacity Auction and the zone's net cleared Capacity Supply Obligations (total acquired less total shed) in the substitution auction including net cleared Capacity Supply Obligations in the nested Capacity Zone is less than its zone threshold quantity specified in Section III.13.2.8.1.1, then supply offers and demand bids in the substitution auction in the export-constrained Capacity Zone (excluding supply offers and demand bids in the nested Capacity Zone that are not treated as offers and bids in the export-constrained Capacity Zone pursuant to Section III.13.2.8.1.2(ii)) shall be treated as offers and bids in the Rest-of-Pool Capacity Zone for purposes of determining substitution auction clearing prices.

(ii) if the sum of a nested Capacity Zone's Capacity Supply Obligations awarded in the primary auction-clearing process of the Forward Capacity Auction and the nested Capacity Zone's net cleared Capacity Supply Obligations (total acquired less total shed) in the substitution auction is less than its zone threshold quantity specified in Section III.13.2.8.1.1, then supply offers and demand bids in the substitution auction in the nested Capacity Zone shall be treated as offers and bids in the export-constrained Capacity Zone within which the nested Capacity Zone is located, for purposes of determining substitution auction clearing prices.

The substitution auction clearing prices for the Rest-of-Pool Capacity Zone and for any constrained zones pooled with the Rest-of-Pool Capacity Zone for pricing purposes shall be determined by the price of the

demand bid or supply offer that is marginal. If a demand bid associated with a Proxy De-List Bid is marginal, then the substitution auction clearing prices shall be set equal to the Capacity Clearing Prices.

The substitution auction clearing price for a constrained Capacity Zone that is not pooled with the Rest-of-Pool Capacity Zone for pricing purposes shall be determined by the price of the demand bid or supply offer associated with the separately-priced constrained Capacity Zone that is marginal. If a demand bid associated with a Proxy De-List Bid is marginal, then the substitution auction clearing price shall be set equal to the Capacity Clearing Price for the constrained Capacity Zone.

The substitution auction clearing price for a nested export-constrained Capacity Zone that is not pooled with the export-constrained Capacity Zone in which it is located for pricing purposes shall be determined by the price of the demand bid or supply offer that is marginal in the nested export-constrained Capacity Zone. If a demand bid associated with a Proxy De-List Bid is marginal, then the substitution auction clearing price for the nested export-constrained Capacity Zone shall be equal to the Capacity Clearing Price for that nested export-constrained Capacity Zone.

If the net quantity of Capacity Supply Obligations awarded in the primary Forward Capacity Auction and substitution auction over an interface between the New England Control Area and an external Control Area is less than that interface's approved capacity transfer limit (net of tie benefits, or net of HQICC in the case of the Phase I/II HVDC-TF), then supply offers and demand bids in the substitution auction at the interface shall be treated as offers and bids in the modeled Capacity Zone associated with that interface for purposes of determining substitution auction clearing prices.

If the net quantity of Capacity Supply Obligations awarded in the primary Forward Capacity Auction and substitution auction over an interface between the New England Control Area and an external Control Area is equal to that interface's approved capacity transfer limit (net of tie benefits, or net of HQICC in the case of the Phase I/II HVDC-TF), then the substitution auction clearing price for that interface will be determined by the demand bid or supply offer that is marginal at that interface. If a cleared demand bid associated with a Proxy De-List Bid is marginal at the external interface, then the substitution auction clearing price for that interface shall be set equal to the Capacity Clearing Price for that interface.

The substitution auction clearing price for an import-constrained Capacity Zone where the total Capacity Supply Obligations awarded in the primary action-clearing process of the Forward Capacity Auction are greater than or equal to the zone's threshold quantity specified in Section III.13.2.8.1.1 shall not be lower

than the substitution auction clearing price for the Rest-of-Pool Capacity Zone.

The substitution auction clearing price for an export-constrained Capacity Zone that is not a nested export-constrained Capacity Zone, where the total Capacity Supply Obligations awarded in the primary auction-clearing process of the Forward Capacity Auction are less than or equal to the zone's threshold quantity specified in Section III.13.2.8.1.1 shall not exceed the substitution auction clearing price for the Rest-of-Pool Capacity Zone.

The substitution auction clearing price for a nested export-constrained Capacity Zone where the total Capacity Supply Obligations awarded in the primary auction-clearing process of the Forward Capacity Auction are less than or equal to the zone's threshold quantity specified in Section III.13.2.8.1.1 shall not exceed the substitution auction clearing price for the Capacity Zone within which it is located.

The substitution auction clearing price at an external interface shall not exceed the substitution auction clearing price in the Capacity Zone connected to the external interface.

If, pursuant to the rules specified above, the substitution auction clearing price for any Capacity Zone or external interface would exceed the Capacity Clearing Price for that location, the substitution auction clearing price for that location only is set equal to its Capacity Clearing Price.

The substitution auction clearing price for any Capacity Zone or external interface cannot be less than negative one multiplied by the Forward Capacity Auction Starting Price.

III.13.2.8.2. Supply Offers in the Substitution Auction.

III.13.2.8.2.1. Supply Offers.

To participate as supply in the substitution auction, a Project Sponsor for a New Capacity Resource must meet the following criteria:

(a) The Project Sponsor and the New Capacity Resource must meet all the requirements for participation in the Forward Capacity Auction specified in Section III.13.1.

(b) The Project Sponsor must elect to have the resource participate in the substitution auction during the New Capacity Show of Interest Window. Pursuant to an election, the resource's total amount of FCA Qualified Capacity that qualifies as a New Capacity Resource will be obligated to

participate in the substitution auction, including any capacity of a Renewable Technology Resource that was not qualified due to proration pursuant to Section III.13.1.1.2.10(a), and subject to the other provisions of this Section III.13.2.8.2.

(c) The Project Sponsor must certify that the New Capacity Resource is a Sponsored Policy Resource as part of the submission of the New Capacity Qualification Package.

Substitution auction supply offers are rationable.

A resource participating in the Forward Capacity Auction as a New Generating Capacity Resource pursuant to Section III.13.1.1.1.2 (resources previously counted as capacity resources) is not eligible to participate as supply in the substitution auction. A resource is not eligible to participate as supply in the substitution auction if it has submitted a demand bid for the substitution auction.

A Composite FCM Transaction comprised of a summer resource that is a Sponsored Policy Resource is eligible to participate as supply in the substitution auction.

A Conditional Qualified New Resource may participate in the substitution auction provided that the resource with which it has overlapping interconnection impacts: (i) did not receive a Capacity Supply Obligation, fully or partially, in the primary auction-clearing process, and: (ii) is not eligible to participate in the substitution auction. A resource having a higher priority in the queue than a Conditional Qualified New Resource with which it has overlapping interconnection impact may participate in the substitution auction provided that the Conditional Qualified New Resource did not receive a Capacity Supply Obligation, fully or partially, in the primary auction-clearing process.

III.13.2.8.2.2. Supply Offer Prices.

Project Sponsors must submit substitution auction supply offer prices no later than five Business Days after the deadline for submission of offers composed of separate resources.

A substitution auction supply offer must be in the form of a curve (with up to five price-quantity pairs). The curve may not decrease in quantity as the price increases. A supply offer price for the substitution auction may not be greater than the Forward Capacity Auction Starting Price or lower than negative one multiplied by the Forward Capacity Auction Starting Price.

If the offer quantity does not equal the resource's FCA Qualified Capacity, the quantity for which no offer price was submitted will be assigned a price equal to the Forward Capacity Auction Starting Price.

III.13.2.8.2.3. Supply Offers Entered into the Substitution Auction

Supply offers for resources that satisfy all of the criteria in Section III.13.2.8.2.1 to participate in the substitution auction may be adjusted prior to conducting the substitution auction-clearing process using the following adjustments:

(a) Any portion of a resource's FCA Qualified Capacity that was cleared (received a Capacity Supply Obligation) in the primary auction-clearing process will be removed from the resource's substitution auction supply offer beginning with the lowest priced price-quantity pairs.

(b) After performing the adjustment specified in Section III.13.2.8.2.3(a), any price-quantity pairs in a resource's substitution auction supply offer with a price greater than the Capacity Clearing Price for the resource's Capacity Zone or external interface are removed from the offer.

III.13.2.8.3. Demand Bids in the Substitution Auction.

III.13.2.8.3.1. Demand Bids.

Market Participants with Existing Generating Capacity Resources or Existing Import Capacity Resources associated with External Elective Transmission Upgrades may elect to submit demand bids for the substitution auction for those resources by the Existing Capacity Retirement Deadline. The election must specify the total amount of the resource's Qualified Capacity that will be associated with its demand bid.

A resource, including any portion of an existing resource that qualifies as a New Capacity Resource, must have achieved FCM Commercial Operation no later than seven days after the issuance by the ISO of the qualification determination notification described in Section III.13.1.2.4(b) in order to participate as demand in the substitution auction.

Regardless of whether an election is made, a demand bid is required for any portion of a resource that is associated with a Retirement De-List Bid, provided that the entire resource has achieved FCM Commercial Operation no later than seven days after the issuance by the ISO of the qualification determination notification described in Section III.13.1.2.4(b).

A resource for which a demand bid election has been made cannot participate in a Composite FCM Transaction, cannot be designated as a Self-Supplied FCA Resource, and will not have incremental summer or winter capacity that does not span the entire Capacity Commitment Period subjected to the treatment specified in Section III.13.1.1.1.3.A.

Demand bids are non-rationable.

A demand bid will be entered into the substitution auction for the portion of the resource that receives a Capacity Supply Obligation in the primary auction-clearing process, subject to the other provisions of this Section III.13.2.8.3. A resource, or portion thereof, associated with a cleared demand bid shall be retired from all New England Markets at the start of the Capacity Commitment Period associated with the Forward Capacity Auction.

III.13.2.8.3.1A Substitution Auction Test Prices.

(a) **Participant-Submitted Test Price.** For auctions associated with a Capacity Commitment Period that begins on or after June 1, 2023, Market Participants that submit a substitution auction demand bid must submit a test price, calculated using the method described below, by the Existing Capacity Retirement Deadline.

The test price for the capacity associated with a resource's demand bid must be calculated using the same methodology as a Retirement De-List Bid, except that a Market Participant may not submit test prices for multiple price-quantity segments but must submit a single test price using, as necessary, aggregated cost and revenue data. The test price must be accompanied by the same documentation required for Retirement De-List Bids above the Dynamic De-List Bid Threshold pursuant to Section III.13.1.2.3.2.1. A Market Participant must submit a test price regardless of whether the price is below the Dynamic De-List Bid Threshold.

A Market Participant is not required to submit a test price for any resource for which the demand bid is less than 3 MW. The applicable test price for any such resource is $0.00/kW-month.

(b) **IMM-Determined Test Price.** The Internal Market Monitor shall review each test price submission using the methodology specified in Section III.13.1.2.3.2.1 for evaluating Retirement De-List Bids, regardless of whether the submitted test price is below the Dynamic De-List Bid Threshold. For purposes of this review, the expected revenues for a cleared substitution auction demand bid shall not be

included as a component of opportunity costs. After due consideration and consultation with the Market Participant, as appropriate, the Internal Market Monitor shall replace the submitted test price with an IMM-determined test price if the submitted test price is not consistent with the sum of the net present value of the resource's expected cash flows plus reasonable expectations about the resource's Capacity Performance Payments plus reasonable opportunity costs.

The Internal Market Monitor's determination regarding a Market Participant-submitted test price shall be included in the retirement determination notification described in Section III.13.1.2.4(a) and in the filing made to the Commission as described in Section III.13.8.1(a).

The test price used for purposes of the substitution auction shall be the Market Participant-submitted test price, as adjusted by the Internal Market Monitor pursuant to this Section III.13.2.8.3.1A(b), and as further adjusted by the Commission in response to the Internal Market Monitor's filing pursuant to Section III.13.1.2.4(a).

III.13.2.8.3.2. Demand Bid Prices.

Market Participants must submit substitution auction demand bid prices no later than five Business Days after the deadline for submission of offers composed of separate resources.

A substitution auction demand bid must be in the form of a curve (with up to five price-quantity pairs). The curve may not decrease in quantity as the price decreases. A demand bid price for the substitution auction may not be greater than the Forward Capacity Auction Starting Price or lower than negative one multiplied by the Forward Capacity Auction Starting Price.

If the bid quantity does not equal the total bid amount submitted by the Market Participant or required for a Retirement De-List Bid pursuant to Section III.13.2.8.3.1, the quantity for which no bid price was specified will be assigned a price equal to negative one multiplied by the Forward Capacity Auction Starting Price.

For auctions associated with a Capacity Commitment Period that begins on or after June 1, 2023, Market Participants may elect either of the demand bid adjustment methods specified in Section III.13.2.8.3.3(b) for the resource by no later than five Business Days after the deadline for submission of offers composed of separate resources. If no such election is made, the adjustment applied shall be the method specified in Section III.13.2.8.3.3(b)(i).

III.13.2.8.3.3. Demand Bids Entered into the Substitution Auction.

If a resource is determined to be needed for reliability pursuant to Section III.13.2.5.2.5, then any demand bid associated with the resource will not be further included in the substitution auction. If a resource is awarded a Capacity Supply Obligation in the primary auction-clearing process and the Capacity Clearing Price is less than ninety percent of the resource's test price as established pursuant to Section III.13.2.8.3.1A, then the resource's demand bid will not be included in the substitution auction.

Demand bids for resources that satisfy all of the criteria in Section III.13.2.8.3.1 to participate in the substitution auction will be adjusted prior to conducting the substitution auction-clearing process using the following adjustments:

(a) For the substitution auction associated with the Capacity Commitment Period beginning on June 1, 2022, any portion of a resource's demand bid that exceeds its Capacity Supply Obligation awarded in the primary auction-clearing process will be removed from the substitution auction demand bid beginning with the highest priced price-quantity pairs.

(b) For substitution auctions associated with a Capacity Commitment Period that begins on or after June 1, 2023, a resource's demand bid will be adjusted using one of the following methods as elected pursuant to Section III.13.2.8.3.2:

(i) The portion of a resource's capacity that did not receive a Capacity Supply Obligation in the primary auction-clearing process will be removed from the substitution auction demand bid beginning with the highest priced price-quantity pair.

(ii) Any portion of a resource's demand bid that exceeds its Capacity Supply Obligation awarded in the primary auction-clearing process will be removed from the substitution auction demand bid beginning with the lowest priced price-quantity pair.

(c) After performing the modification specified in Sections III.13.2.8.3.3(a) or III.13.2.8.3.3(b), any price-quantity pairs in a resource's substitution auction demand bid with a price greater than the Capacity Clearing Price for the resource's Capacity Zone or external interface will have its price reduced to the Capacity Clearing Price for the resource's Capacity Zone or external interface.

Except as provided in Section III.13.2.5.2.1(c), a rationable demand bid will be entered into the substitution auction on behalf of any Proxy De-List Bid associated with a Permanent De-List Bid or

Retirement De-List Bid. The demand bid quantity will equal the portion of the Proxy De-List Bid that was not cleared (received a Capacity Supply Obligation) in the first run of the primary auction-clearing process. The demand bid will have priority to clear before non-rationable demand bids.

SECTION III

MARKET RULE 1

APPENDIX A

MARKET MONITORING, REPORTING AND MARKET POWER MITIGATION

APPENDIX A

MARKET MONITORING, REPORTING AND MARKET POWER MITIGATION

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MARKET MONITORING, REPORTING AND MARKET POWER MITIGATION

III.A.1. Introduction and Purpose; Structure and Oversight: Independence.

III.A.1.1. Mission Statement.

The mission of the Internal Market Monitor and External Market Monitor shall be (1) to protect both consumers and Market Participants by the identification and reporting of market design flaws and market power abuses; (2) to evaluate existing and proposed market rules, tariff provisions and market design elements to remove or prevent market design flaws and recommend proposed rule and tariff changes to the ISO; (3) to review and report on the performance of the New England Markets; (4) to identify and notify the Commission of instances in which a Market Participant's behavior, or that of the ISO, may require investigation; and (5) to carry out the mitigation functions set forth in this ***Appendix A.***

III.A.1.2. Structure and Oversight.

The market monitoring and mitigation functions contained in this ***Appendix A*** shall be performed by the Internal Market Monitor, which shall report to the ISO Board of Directors and, for administrative purposes only, to the ISO Chief Executive Officer, and by an External Market Monitor selected by and reporting to the ISO Board of Directors. Members of the ISO Board of Directors who also perform management functions for the ISO shall be excluded from oversight and governance of the Internal Market Monitor and External Market Monitor. The ISO shall enter into a contract with the External Market Monitor addressing the roles and responsibilities of the External Market Monitor as detailed in this ***Appendix A***. The ISO shall file its contract with the External Market Monitor with the Commission. In order to facilitate the performance of the External Market Monitor's functions, the External Market Monitor shall have, and the ISO's contract with the External Market Monitor shall provide for, access by the External Market Monitor to ISO data and personnel, including ISO management responsible for market monitoring, operations and billing and settlement functions. Any proposed termination of the contract with the External Market Monitor or modification of, or other limitation on, the External Market Monitor's scope of work shall be subject to prior Commission approval.

III.A.1.3. Data Access and Information Sharing.

The ISO shall provide the Internal Market Monitor and External Market Monitor with access to all market data, resources and personnel sufficient to enable the Internal Market Monitor and External Market Monitor to perform the market monitoring and mitigation functions provided for in this ***Appendix A***.

This access shall include access to any confidential market information that the ISO receives from another independent system operator or regional transmission organization subject to the Commission's jurisdiction, or its market monitor, as part of an investigation to determine (a) if a Market Violation is occurring or has occurred, (b) if market power is being or has been exercised, or (c) if a market design flaw exists. In addition, the Internal Market Monitor and External Market Monitor shall have full access to the ISO's electronically generated information and databases and shall have exclusive control over any data created by the Internal Market Monitor or External Market Monitor. The Internal Market Monitor and External Market Monitor may share any data created by it with the ISO, which shall maintain the confidentiality of such data in accordance with the terms of the ISO New England Information Policy.

III.A.1.4. Interpretation.

In the event that any provision of any ISO New England Filed Document is inconsistent with the provisions of this ***Appendix A***, the provisions of ***Appendix A*** shall control. Notwithstanding the foregoing, Sections III.A.1.2, III.A.2.2 (a)-(c), (e)-(h), Section III.A.2.3 (a)-(g), (i), (n) and Section III.A.17.3 are also part of the Participants Agreement and cannot be modified in either ***Appendix A*** or the Participants Agreement without a corresponding modification at the same time to the same language in the other document.

III.A.1.5. Definitions.

Capitalized terms not defined in this ***Appendix A*** are defined in the definitions section of Section I of the Tariff.

III.A.2. Functions of the Market Monitor.

III.A.2.1. Core Functions of the Internal Market Monitor and External Market Monitor.

The Internal Market Monitor and External Market Monitor will perform the following core functions:

(a) Evaluate existing and proposed market rules, tariff provisions and market design elements, and recommend proposed rule and tariff changes to the ISO, the Commission, Market Participants, public utility commissioners of the six New England states, and to other interested entities, with the understanding that the Internal Market Monitor and External Market Monitor are not to effectuate any proposed market designs (except as specifically provided in Section III.A.2.4.4, Section III.A.9 and Section III.A.10 of this ***Appendix A***). In the event the Internal Market Monitor or External Market Monitor believes broader dissemination could lead to exploitation, it shall limit distribution of its

identifications and recommendations to the ISO and to the Commission, with an explanation of why broader dissemination should be avoided at that time. Nothing in this Section III.A.2.1 (a) shall prohibit or restrict the Internal Market Monitor and External Market Monitor from implementing Commission accepted rule and tariff provisions regarding market monitoring or mitigation functions that, according to the terms of the applicable rule or tariff language, are to be performed by the Internal Market Monitor or External Market Monitor.

(b) Review and report on the performance of the New England Markets to the ISO, the Commission, Market Participants, the public utility commissioners of the six New England states, and to other interested entities.

(c) Identify and notify the Commission's Office of Enforcement of instances in which a Market Participant's behavior, or that of the ISO, may require investigation, including suspected tariff violations, suspected violations of Commission-approved rules and regulations, suspected market manipulation, and inappropriate dispatch that creates substantial concerns regarding unnecessary market inefficiencies.

III.A.2.2. Functions of the External Market Monitor.

To accomplish the functions specified in Section III.A.2.1 of this ***Appendix A***, the External Market Monitor shall perform the following functions:

(a) Review the competitiveness of the New England Markets, the impact that the market rules and/or changes to the market rules will have on the New England Markets and the impact that the ISO's actions have had on the New England Markets. In the event that the External Market Monitor uncovers problems with the New England Markets, the External Market Monitor shall promptly inform the Commission, the Commission's Office of Energy Market Regulation staff, the ISO Board of Directors, the public utility commissions for each of the six New England states, and the Market Participants of its findings in accordance with the procedures outlined in Sections III.A.19 and III.A.20 of this ***Appendix A***, provided that in the case of Market Participants and the public utility commissions, information in such findings shall be redacted as necessary to comply with the ISO New England Information Policy. Notwithstanding the foregoing, in the event the External Market Monitor believes broader dissemination could lead to exploitation, it shall limit distribution of its identifications to the ISO and to the Commission, with an explanation of why broader dissemination should be avoided at that time.

(b) Perform independent evaluations and prepare annual and ad hoc reports on the overall competitiveness and efficiency of the New England Markets or particular aspects of the New England

Markets, including the adequacy of this ***Appendix A***, in accordance with the provisions of Section III.A.17 of this ***Appendix A***.

(c) Conduct evaluations and prepare reports on its own initiative or at the request of others.

(d) Monitor and review the quality and appropriateness of the mitigation conducted by the Internal Market Monitor. In the event that the External Market Monitor discovers problems with the quality or appropriateness of such mitigation, the External Market Monitor shall promptly inform the Commission, the Commission's Office of Energy Market Regulation staff, the ISO Board of Directors, the public utility commissions for each of the six New England states, and the Market Participants of its findings in accordance with the procedures outlined in Sections III.A.19 and/or III.A.20 of this ***Appendix A,*** provided that in the case of Market Participants and the public utility commissions, information in such findings shall be redacted as necessary to comply with the ISO New England Information Policy. Notwithstanding the foregoing, in the event the External Market Monitor believes broader dissemination could lead to exploitation, it shall limit distribution of its identifications to the ISO and to the Commission, with an explanation of why broader dissemination should be avoided at that time.

(e) Prepare recommendations to the ISO Board of Directors and the Market Participants on how to improve the overall competitiveness and efficiency of the New England Markets or particular aspects of the New England Markets, including improvements to this ***Appendix A***.

(f) Recommend actions to the ISO Board of Directors and the Market Participants to increase liquidity and efficient trade between regions and improve the efficiency of the New England Markets.

(g) Review the ISO's filings with the Commission from the standpoint of the effects of any such filing on the competitiveness and efficiency of the New England Markets. The External Market Monitor will have the opportunity to comment on any filings under development by the ISO and may file comments with the Commission when the filings are made by the ISO. The subject of any such comments will be the External Market Monitor's assessment of the effects of any proposed filing on the competitiveness and efficiency of the New England Markets, or the effectiveness of this ***Appendix A***, as appropriate.

(h) Provide information to be directly included in the monthly market updates that are provided at the meetings of the Market Participants.

III.A.2.3. Functions of the Internal Market Monitor.

To accomplish the functions specified in Section III.A.2.1 of this ***Appendix A***, the Internal Market Monitor shall perform the following functions:

(a) Maintain ***Appendix A*** and consider whether ***Appendix A*** requires amendment. Any amendments deemed to be necessary by the Internal Market Monitor shall be undertaken after consultation with Market Participants in accordance with Section 11 of the Participants Agreement.

(b) Perform the day-to-day, real-time review of market behavior in accordance with the provisions of this ***Appendix A***.

(c) Consult with the External Market Monitor, as needed, with respect to implementing and applying the provisions of this ***Appendix A.***

(d) Identify and notify the Commission's Office of Enforcement staff of instances in which a Market Participant's behavior, or that of the ISO, may require investigation, including suspected Tariff violations, suspected violations of Commission-approved rules and regulations, suspected market manipulation, and inappropriate dispatch that creates substantial concerns regarding unnecessary market inefficiencies, in accordance with the procedures outlined in Section III.A.19 of this ***Appendix A.***

(e) Review the competitiveness of the New England Markets, the impact that the market rules and/or changes to the market rules will have on the New England Markets and the impact that ISO's actions have had on the New England Markets. In the event that the Internal Market Monitor uncovers problems with the New England Markets, the Internal Market Monitor shall promptly inform the Commission, the Commission's Office of Energy Market Regulation staff, the ISO Board of Directors, the public utility commissions for each of the six New England states, and the Market Participants of its findings in accordance with the procedures outlined in Sections III.A.19 and III.A.20 of this ***Appendix A***, provided that in the case of Market Participants and the public utility commissions, information in such findings shall be redacted as necessary to comply with the ISO New England Information Policy. Notwithstanding the foregoing, in the event the Internal Market Monitor believes broader dissemination could lead to exploitation, it shall limit distribution of its identifications to the ISO and to the Commission, with an explanation of why broader dissemination should be avoided at that time.

(f) Provide support and information to the ISO Board of Directors and the External Market Monitor consistent with the Internal Market Monitor's functions.

(g) Prepare an annual state of the market report on market trends and the performance of the New England Markets, as well as less extensive quarterly reports, in accordance with the provisions of Section III.A.17 of this ***Appendix A***.

(h) Make one or more of the Internal Market Monitor staff members available for regular conference calls, which may be attended, telephonically or in person, by Commission and state commission staff, by representatives of the ISO, and by Market Participants. The information to be provided in the

Internal Market Monitor conference calls is generally to consist of a review of market data and analyses of the type regularly gathered and prepared by the Internal Market Monitor in the course of its business, subject to appropriate confidentiality restrictions. This function may be performed through making a staff member of the Internal Market Monitor available for the monthly meetings of the Market Participants and inviting Commission staff and the staff of state public utility commissions to those monthly meetings.

(i) Be primarily responsible for interaction with external Control Areas, the Commission, other regulators and Market Participants with respect to the matters addressed in this ***Appendix A***.

(j) Monitor for conduct whether by a single Market Participant or by multiple Market Participants acting in concert, including actions involving more than one Resource, that may cause a material effect on prices or other payments in the New England Markets if exercised from a position of market power, and impose appropriate mitigation measures if such conduct is detected and the other applicable conditions for the imposition of mitigation measures as set forth in this ***Appendix A*** are met. The categories of conduct for which the Internal Market Monitor shall perform monitoring for potential mitigation are:

(i) *Economic withholding*, that is, submitting a Supply Offer for a Resource that is unjustifiably high and violates the economic withholding criteria set forth in Section III.A.5 so that (i) the Resource is not or will not be dispatched or scheduled, or (ii) the bid or offer will set an unjustifiably high market clearing price.

(ii) *Uneconomic production from a Resource*, that is, increasing the output of a Resource to levels that would otherwise be uneconomic, absent an order of the ISO, in order to cause, and obtain benefits from, a transmission constraint.

(iii) *Anti-competitive Increment Offers and Decrement Bids*, which are bidding practices relating to Increment Offers and Decrement Bids that cause Day-Ahead LMPs not to achieve the degree of convergence with Real-Time LMPs that would be expected in a workably competitive market, more fully addressed in Section III.A.11 of this ***Appendix A***.

(iv) *Anti-competitive Demand Bids*, which are addressed in Section III.A.10 of this ***Appendix A.***

(v) Other categories of conduct that have material effects on prices or NCPC payments in the New England Markets. The Internal Market Monitor, in consultation with the External Market Monitor, shall; (i) seek to amend ***Appendix A*** as may be appropriate to include any such conduct that would substantially distort or impair the competitiveness of any of

the New England Markets; and (ii) seek such other authorization to mitigate the effects of such conduct from the Commission as may be appropriate.

(k) Perform such additional monitoring as the Internal Market Monitor deems necessary, including without limitation, monitoring for:

(i) Anti-competitive gaming of Resources;

(ii) Conduct and market outcomes that are inconsistent with competitive markets;

(iii) Flaws in market design or software or in the implementation of rules by the ISO that create inefficient incentives or market outcomes;

(iv) Actions in one market that affect price in another market;

(v) Other aspects of market implementation that prevent competitive market results, the extent to which market rules, including this ***Appendix A***, interfere with efficient market operation, both short-run and long-run; and

(vi) Rules or conduct that creates barriers to entry into a market.

The Internal Market Monitor will include significant results of such monitoring in its reports under Section III.A.17 of this ***Appendix A***. Monitoring under this Section III.A.2.3(k) cannot serve as a basis for mitigation under III.A.11 of this ***Appendix A.*** If the Internal Market Monitor concludes as a result of its monitoring that additional specific monitoring thresholds or mitigation remedies are necessary, it may proceed under Section III.A.20.

(l) Propose to the ISO and Market Participants appropriate mitigation measures or market rule changes for conduct that departs significantly from the conduct that would be expected under competitive market conditions but does not rise to the thresholds specified in Sections III.A.5, III.A.10, or III.A.11. In considering whether to recommend such changes, the Internal Market Monitor shall evaluate whether the conduct has a significant effect on market prices or NCPC payments as specified below. The Internal Market Monitor will not recommend changes if it determines, from information provided by Market Participants (or parties that would be subject to mitigation) or from other information available to the Internal Market Monitor, that the conduct and associated price or NCPC payments under investigation are attributable to legitimate competitive market forces or incentives.

(m) Evaluate physical withholding of Supply Offers in accordance with Section III.A.4 below for referral to the Commission in accordance with ***Appendix B*** of this Market Rule l.

(n) If and when established, participate in a committee of regional market monitors to review issues associated with interregional transactions, including any barriers to efficient trade and competition.

III.A.2.4. Overview of the Internal Market Monitor's Mitigation Functions.

III.A.2.4.1. Purpose.

The mitigation measures set forth in this ***Appendix A*** for mitigation of market power are intended to provide the means for the Internal Market Monitor to mitigate the market effects of any actions or transactions that are without a legitimate business purpose and that are intended to or foreseeably could manipulate market prices, market conditions, or market rules for electric energy or electricity products. Actions or transactions undertaken by a Market Participant that are explicitly contemplated in Market Rule l (such as virtual supply or load bidding) or taken at the direction of the ISO are not in violation of this ***Appendix A***. These mitigation measures are intended to minimize interference with open and competitive markets, and thus to permit to the maximum extent practicable, price levels to be determined by competitive forces under the prevailing market conditions. To that end, the mitigation measures authorize the mitigation of only specific conduct that exceeds well-defined thresholds specified below. When implemented, mitigation measures affecting the LMP or clearing prices in other markets will be applied *ex ante*. Nothing in this ***Appendix A***, including the application of a mitigation measure, shall be deemed to be a limitation of the ISO's authority to evaluate Market Participant behavior for potential sanctions under ***Appendix B*** of this Market Rule 1.

III.A.2.4.2. Conditions for the Imposition of Mitigation.

(a) Imposing Mitigation. To achieve the foregoing purpose and objectives, mitigation measures are imposed pursuant to Sections III.A.5, III.A.10, and III.A.11 below:

(b) Notwithstanding the foregoing or any other provision of this ***Appendix A***, and as more fully described in Section III.B.3.2.6 of ***Appendix B*** to this Market Rule 1, certain economic decisions shall not be deemed a form of withholding or otherwise inconsistent with competitive conduct.

III.A.2.4.3. Applicability.

Mitigation measures may be applied to Supply Offers, Increment Offers, Demand Bids, and Decrement Bids, as well as to the scheduling or operation of a generation unit or transmission facility.

III.A.2.4.4. Mitigation Not Provided for Under This *Appendix A*.

The Internal Market Monitor shall monitor the New England Markets for conduct that it determines constitutes an abuse of market power but does not trigger the thresholds specified below for the imposition of mitigation measures by the Internal Market Monitor. If the Internal Market Monitor identifies any such conduct, and in particular conduct exceeding the thresholds specified in this ***Appendix A***, it may make a filing under §205 of the Federal Power Act ("§205") with the Commission requesting authorization to apply appropriate mitigation measures. Any such filing shall identify the particular conduct the Internal Market Monitor believes warrants mitigation, shall propose a specific mitigation measure for the conduct, and shall set forth the Internal Market Monitor's justification for imposing that mitigation measure.

III.A.2.4.5. Duration of Mitigation.

Any mitigation measure imposed on a specific Market Participant, as specified below, shall expire not later than six months after the occurrence of the conduct giving rise to the measure, or at such earlier time as may be specified by the Internal Market Monitor or as otherwise provided in this ***Appendix A*** or in ***Appendix B*** to this Market Rule 1.

III.A.3. Consultation Prior to Determination of Reference Levels for Physical and Financial Parameters of Resources; Fuel Price Adjustments.

Upon request of a Market Participant or at the initiative of the Internal Market Monitor, the Internal Market Monitor shall consult with a Market Participant with respect to the information and analysis used to determine Reference Levels under Section III.A.7 for that Market Participant**.** In order for the Internal Market Monitor to revise Reference Levels or treat an offer as not violating applicable conduct tests specified in Section III.A.5.5 for an Operating Day for which the offer is submitted, all cost data and other information, other than automated index-based cost data received by the Internal Market Monitor from third party vendors, cost data and information calculated by the Internal Market Monitor, and cost data and information provided under the provisions of Section III.A.3.1 or Section III.A.3.2, must be submitted by a Market Participant, and all consultations must be completed, no later than 5:00 p.m. of the second business day prior to the Operating Day for which the Reference Level will be effective. Adjustments to fuel prices after this time must be submitted in accordance with the fuel price adjustment provisions in Section III.A.3.4.

III.A.3.1. Consultation Prior to Offer.

If an event occurs within the 24 hour period prior to the Operating Day that a Market Participant, including a Market Participant that is not permitted to submit a fuel price adjustment pursuant to Section III.A.3.4(d) believes will cause the operating cost of a Resource to exceed the level that would violate one of the conduct tests specified in Section III.A.5 of this ***Appendix A***, the Market Participant may contact the Internal Market Monitor to provide an explanation of the increased costs. In order for the information to be considered for the purposes of the Day-Ahead Energy Market, the Market Participant must contact the Internal Market Monitor at least 30 minutes prior to the close of the Day-Ahead Energy Market. In order for the information to be considered for purposes of the first commitment analysis performed following the close of the Re-Offer Period, the Market Participant must contact the Internal Market Monitor at least 30 minutes prior to the close of the Re-Offer Period. Cost information submitted thereafter shall be considered in subsequent commitment and dispatch analyses if received between 8:00 a.m. and 5:00 p.m. and at least one hour prior to the close of the next hourly Supply Offer submittal period. If the Internal Market Monitor determines that there is an increased cost, the Internal Market Monitor will either update the Reference Level or treat an offer as not violating applicable conduct tests specified in Section III.A.5.5 for the Operating Day for which the offer is submitted. Any request and all supporting cost data and other verifiable supporting information must be submitted to the Internal Market Monitor prior to the Market participant's submission of the offer.

If a Market Participant believes that the fuel price determined under Section III.A.7.5(e) should be modified, it may contact the Internal Market Monitor to request a change to the fuel price and provide an explanation of the basis for the change. Any request to change the fuel price determined under Section III.A.7.5(e) must be received between the hours of 8:00 a.m. and 5:00 p.m. on any day.

III.A.3.2. Dual Fuel Resources.

In evaluating bids or offers under this ***Appendix A*** for dual fuel Resources, the Internal Market Monitor shall utilize the fuel type specified in the Supply Offer for the calculation of Reference Levels pursuant to Section III.A.7 below. If a Market Participant specifies a fuel type in the Supply Offer that, at the time the Supply Offer is submitted, is the higher cost fuel available to the Resource, then if the ratio of the higher cost fuel to the lower cost fuel, as calculated in accordance with the formula specified below, is greater than 1.75, the Market Participant must within five Business Days:

(a) provide the Internal Market Monitor with written verification as to the cause for the use of the higher cost fuel.

(b) provide the Internal Market Monitor with evidence that the higher cost fuel was used.

If the Market Participant fails to provide supporting information demonstrating the use of the higher-cost fuel within five Business Days of the Operating Day, then the Reference Level based on the lower cost fuel will be used in place of the Supply Offer for settlement purposes.

For purposes of this Section III.A.3.2, the ratio of the Resource's higher cost fuel to the lower cost fuel is calculated as, for the two primary fuels utilized in the dispatch of the Resource, the maximum fuel index price for the Operating Day divided by the minimum fuel index price for the Operating Day, using the two fuel indices that are utilized in the calculation of the Resource's Reference Levels for the Day-Ahead Energy Market for that Operating Day.

III.A.3.3. Market Participant Access to its Reference Levels.

The Internal Market Monitor will make available to the Market Participant the Reference Levels applicable to that Market Participant's Supply Offers through the MUI. Updated Reference Levels will be made available whenever calculated. The Market Participant shall not modify such Reference Levels in the ISO's or Internal Market Monitor's systems.

III.A.3.4. Fuel Price Adjustments.

(a) A Market Participant may submit a fuel price, to be used in calculating the Reference Levels for a Resource's Supply Offer, whenever the Market Participant's expected price to procure fuel for the Resource will be greater than that used by the Internal Market Monitor in calculating the Reference Levels for the Supply Offer. A fuel price may be submitted for Supply Offers entered in the Day-Ahead Energy Market, the Re-Offer Period, or for a Real-Time Offer Change. A fuel price is subject to the following conditions:

(i) In order for the submitted fuel price to be utilized in calculating the Reference Levels for a Supply Offer, the fuel price must be submitted prior to the applicable Supply Offer deadline,

(ii) The submitted fuel price must reflect the price at which the Market Participant expects to be able to procure fuel to supply energy under the terms of its Supply Offer, exclusive of resource-specific transportation costs. Modifications to Reference Levels based on changes to transportation costs must be addressed through the consultation process specified in Section III.A.3.1.

(iii) The submitted fuel price may be no lower than the lesser of (1) 110% of the fuel price used by the Internal Market Monitor in calculating the Reference Levels for the Resource's Supply Offer

or (2) the fuel price used by the Internal Market Monitor in calculating the Reference Levels for the Resource's Supply Offer plus $2.50/MMbtu.

(b) Within five Business Days following submittal of a fuel price, a Market Participant must provide the Internal Market Monitor with documentation or analysis to support the submitted fuel price, which may include but is not limited to (i) an invoice or purchase confirmation for the fuel utilized or (ii) a quote from a named supplier or (iii) a price from a publicly available trading platform or price reporting agency, demonstrating that the submitted fuel price reflects the cost at which the Market Participant expected to purchase fuel for the operating period covered by the Supply Offer, as of the time that the Supply Offer was submitted, under an arm's length fuel purchase transaction. Any amount to be added to the quote from a named supplier, or to a price from a publicly available trading platform or price reporting agency, must be submitted and approved using the provision for consultations prior to the determination of Reference Levels in Section III.A.3. The submitted fuel price must be consistent with the fuel price reflected on the submitted invoice or purchase confirmation for the fuel utilized, the quote from a named supplier or the price from a publicly available trading platform or price reporting agency, plus any approved adder, or the other documentation or analysis provided to support the submitted fuel price.

(c) If, within a 12 month period, the requirements in sub-section (b) are not met for a Resource and, for the time period for which the fuel price adjustment that does not meet the requirements in sub-section (b) was submitted, (i) the Market Participant was determined to be pivotal according to the pivotal supplier test described in Section III.A.5.2.1or (ii) the Resource was determined to be in a constrained area according to the constrained area test described in Section III.A.5.2.2 or (iii) the Resource satisfied any of the conditions described in Section III.A.5.5.6.1, then a fuel price adjustment pursuant to Section III.A.3.4 shall not be permitted for that Resource for up to six months. The following table specifies the number of months for which a Market Participant will be precluded from using the fuel price adjustment, based on the number of times the requirements in sub-section (b) are not met within the 12 month period. The 12 month period excludes any previous days for which the Market Participant was precluded from using the fuel price adjustment. The period of time for which a Market Participant is precluded from using the fuel price adjustment begins two weeks after the most-recent incident occurs.

Number of Incidents	Months Precluded (starting from most-recent incident)
1	2

2 or more	6

III.A.4. Physical Withholding.

III.A.4.1. Identification of Conduct Inconsistent with Competition.

This section defines thresholds used to identify possible instances of physical withholding. This section does not limit the Internal Market Monitor's ability to refer potential instances of physical withholding to the Commission.

Generally, physical withholding involves not offering to sell or schedule the output of or services provided by a Resource capable of serving the New England Markets when it is economic to do so. Physical withholding may include, but is not limited to:

(a) falsely declaring that a Resource has been forced out of service or otherwise become unavailable,

(b) refusing to make a Supply Offer, or schedules for a Resource when it would be in the economic interest absent market power, of the withholding entity to do so,

(c) operating a Resource in Real-Time to produce an output level that is less than the ISO Dispatch Rate, or

(d) operating a transmission facility in a manner that is not economic, is not justified on the basis of legitimate safety or reliability concerns, and contributes to a binding transmission constraint.

III.A.4.2. Thresholds for Identifying Physical Withholding.

III.A.4.2.1. Initial Thresholds.

Except as specified in subsection III.A.4.2.4 below, the following initial thresholds will be employed by the Internal Market Monitor to identify physical withholding of a Resource:

(a) Withholding that exceeds the lower of 10% or 100 MW of a Resource's capacity;

(b) Withholding that exceeds in the aggregate the lower of 5% or 200 MW of a Market Participant's total capacity for Market Participants with more than one Resource; or

(c) Operating a Resource in Real-Time at an output level that is less than 90% of the ISO's Dispatch Rate for the Resource.

III.A.4.2.2. Adjustment to Generating Capacity.

The amounts of generating capacity considered withheld for purposes of applying the foregoing thresholds shall include unjustified deratings, that is, falsely declaring a Resource derated, and the portions of a Resource's available output that are not offered. The amounts deemed withheld shall not include generating output that is subject to a forced outage or capacity that is out of service for maintenance in accordance with an ISO maintenance schedule, subject to verification by the Internal Market Monitor as may be appropriate that an outage was forced.

III.A.4.2.3. Withholding of Transmission.

A transmission facility shall be deemed physically withheld if it is not operated in accordance with ISO instructions and such failure to conform to ISO instructions causes transmission congestion. A transmission facility shall not be deemed withheld if it is subject to a forced outage or is out of service for maintenance in accordance with an ISO maintenance schedule, subject to verification by the Internal Market Monitor as may be appropriate that an outage was forced.

III.A.4.2.4. Resources in Congestion Areas.

Minimum quantity thresholds shall not be applicable to the identification of physical withholding by a Resource in an area the ISO has determined is congested.

III.A.4.3. Hourly Market Impacts.

Before evaluating possible instances of physical withholding for imposition of sanctions, the Internal Market Monitor shall investigate the reasons for the change in accordance with Section III.A.3. If the physical withholding in question is not explained to the satisfaction of the Internal Market Monitor, the Internal Market Monitor will determine whether the conduct in question causes a price impact in the New England Markets in excess of any of the thresholds specified in Section III.A.5, as appropriate.

III.A.5. Mitigation.

III.A.5.1. Resources with Capacity Supply Obligations.

Only Supply Offers associated with Resources with Capacity Supply Obligations will be evaluated for economic withholding in the Day-Ahead Energy Market. All Supply Offers will be evaluated for economic withholding in the Real-Time Energy Market.

III.A.5.1.1. Resources with Partial Capacity Supply Obligations.

Supply Offers associated with Resources with a Capacity Supply Obligation for less than their full capacity shall be evaluated for economic withholding and mitigation as follows:

(a) all Supply Offer parameters shall be reviewed for economic withholding;

(b) the energy price Supply Offer parameter shall be reviewed for economic withholding up to and including the higher of: (i) the block containing the Resource's Economic Minimum Limit, or; (ii) the highest block that includes any portion of the Capacity Supply Obligation;

(c) if a Resource with a partial Capacity Supply Obligation consists of multiple assets, the offer blocks associated with the Resource that shall be evaluated for mitigation shall be determined by using each asset's Seasonal Claimed Capability value in proportion to the total of the Seasonal Claimed Capabilities for all of the assets that make up the Resource. The Lead Market Participant of a Resource with a partial Capacity Supply Obligation consisting of multiple assets may also propose to the Internal Market Monitor the offer blocks that shall be evaluated for mitigation based on an alternative allocation on a monthly basis. The proposal must be made at least five Business Days prior to the start of the month. A proposal shall be rejected by the Internal Market Monitor if the designation would be inconsistent with competitive behavior

III.A.5.2. Structural Tests.

There are two structural tests that determine which mitigation thresholds are applied to a Supply Offer:

(a) if a supplier is determined to be pivotal according to the pivotal supplier test, then the thresholds in Section III.A.5.5.1 "General Threshold Energy Mitigation" and Section III.A.5.5.4 "General Threshold Commitment Mitigation" apply, and;

(b) if a Resource is determined to be in a constrained area according to the constrained area test, then the thresholds in Section III.A.5.5.2 "Constrained Area Energy Mitigation" and Section III.A.5.5.4 "Constrained Area Commitment Mitigation" apply.

III.A.5.2.1. Pivotal Supplier Test.

The pivotal supplier test examines whether a Market Participant has aggregate energy Supply Offers (up to and including Economic Max) that exceed the supply margin in the Real-Time Energy Market. A Market Participant whose aggregate energy associated with Supply Offers exceeds the supply margin is a pivotal supplier.

The supply margin for an interval is the total energy Supply Offers from available Resources (up to and including Economic Max), less total system load (as adjusted for net interchange with other Control Areas, including Operating Reserve). Resources are considered available for an interval if they can provide energy within the interval. The applicable interval for the current operating plan in the Real-Time Energy Market is any of the hours in the plan. The applicable interval for UDS is the interval for which UDS issues instructions.

The pivotal supplier test shall be run prior to each determination of a new operating plan for the Operating Day, and prior to each execution of the UDS.

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III.A.5.2.2. Constrained Area Test.

A Resource is considered to be within a constrained area if:

(a) for purposes of the Real-Time Energy Market, the Resource is located on the import-constrained side of a binding constraint and there is a sensitivity to the binding constraint such that the UDS used to relieve transmission constraints would commit or dispatch the Resource in order to relieve that binding transmission constraint, or;

(b) for purposes of the Day-Ahead Energy Market, the LMP at the Resource's Node exceeds the LMP at the Hub by more than $25/MWh.

III.A.5.3. Calculation of Impact Test in the Day-Ahead Energy Market.

The price impact for the purposes of Section III.A.5.5.2 "Constrained Area Energy Mitigation" is equal to the difference between the LMP at the Resource's Node and the LMP at the Hub.

III.A.5.4. Calculation of Impact Tests in the Real-Time Energy Market.

The energy price impact test applied in the Real-Time Energy Market shall compare two LMPs at the Resource's Node. The first LMP will be calculated based on the Supply Offers submitted for all Resources. If a Supply Offer has been mitigated in a prior interval, the calculation of the first LMP shall be based on the mitigated value. The second LMP shall be calculated substituting Reference Levels for

Supply Offers that have failed the applicable conduct test. The difference between the two LMPs is the price impact of the conduct violation.

A Supply Offer shall be determined to have no price impact if the offer block that violates the conduct test is:

(a) less than the LMP calculated using the submitted Supply Offers, and less than the LMP calculated using Reference Levels for Supply Offers that have failed the conduct test, or;

(b) greater than the LMP calculated using the submitted Supply Offers, and greater than the LMP calculated using Reference Levels for Supply Offers that have failed the conduct test, and the Resource has not been dispatched into the offer block that exceeds the LMP.

III.A.5.5. Mitigation by Type.

III.A.5.5.1. General Threshold Energy Mitigation.

III.A.5.5.1.1. Applicability.

Mitigation pursuant to this section shall be applied to all Supply Offers in the Real-Time Energy Market submitted by a Lead Market Participant that is determined to be a pivotal supplier in the Real-Time Energy Market.

III.A.5.5.1.2. Conduct Test.

A Supply Offer fails the conduct test for general threshold energy mitigation if any offer block price exceeds the Reference Level by an amount greater than 300% or $100/MWh, whichever is lower. Offer block prices below $25/MWh are not subject to the conduct test.

III.A.5.5.1.3. Impact Test.

A Supply Offer that fails the conduct test for general threshold energy mitigation shall be evaluated against the impact test for general threshold energy mitigation. A Supply Offer fails the impact test for general threshold energy mitigation if there is an increase in the LMP greater than 200% or $100/MWh, whichever is lower as determined by the real-time impact test.

III.A.5.5.1.4. Consequence of Failing Both Conduct and Impact Test.

If a Supply Offer fails the general threshold conduct and impact tests, then the financial parameters of the Supply Offer shall be set to their Reference Levels, including all energy offer block prices and all types of Start-Up Fees and the No-Load Fee.

III.A.5.5.2. Constrained Area Energy Mitigation.

III.A.5.5.2.1. Applicability.

Mitigation pursuant to this section shall be applied to Supply Offers in the Day-Ahead Energy Market and Real-Time Energy Market associated with a Resource determined to be within a constrained area.

III.A.5.5.2.2. Conduct Test.

A Supply Offer fails the conduct test for constrained area energy mitigation if any offer block price exceeds the Reference Level by an amount greater than 50% or $25/MWh, whichever is lower.

III.A.5.5.2.3. Impact Test.

A Supply Offer fails the impact test for constrained area energy mitigation if there is an increase greater than 50% or $25/MWh, whichever is lower, in the LMP as determined by the day-ahead or real-time impact test.

III.A.5.5.2.4. Consequence of Failing Both Conduct and Impact Test.

If a Supply Offer fails the constrained area conduct and impact tests, then the financial parameters of the Supply Offer shall be set to their Reference Levels, including all energy offer blocks and all types of Start-Up Fees and the No-Load Fee.

III.A.5.5.3. Manual Dispatch Energy Mitigation.

III.A.5.5.3.1. Applicability.

Mitigation pursuant to this section shall be applied to Supply Offers associated with a Resource, when the Resource is manually dispatched above the Economic Minimum Limit value specified in the Resource's Supply Offer and the energy price parameter of its Supply Offer at the Desired Dispatch Point is greater than the Real-Time Price at the Resource's Node.

III.A.5.5.3.2. Conduct Test.

A Supply Offer fails the conduct test for manual dispatch energy mitigation if any offer block price divided by the Reference Level is greater than 1.10.

III.A.5.5.3.3. Consequence of Failing the Conduct Test.

If a Supply Offer for a Resource fails the manual dispatch energy conduct test, then the financial parameters of the Supply Offer shall be set to their Reference Levels, including all energy offer blocks and all types of Start-Up Fees and the No-Load Fee.

III.A.5.5.4. General Threshold Commitment Mitigation.

III.A.5.5.4.1. Applicability.

Mitigation pursuant to this section shall be applied to all Supply Offers in the Real-Time Energy Market submitted by a Lead Market Participant that is determined to be a pivotal supplier in the Real-Time Energy Market.

III.A.5.5.4.2. Conduct Test.

A Resource shall fail the conduct test for general threshold commitment mitigation if the low Load Cost at Offer divided by the Low Load Cost at Reference Level is greater than 3.00.

III.A.5.5.4.3. Consequence of Failing Conduct Test.

If a Resource fails the general threshold commitment conduct test, then all financial parameters of its Supply Offer are set to their Reference Levels.

III.A.5.5.5. Constrained Area Commitment Mitigation.

III.A.5.5.5.1. Applicability.

Mitigation pursuant to this section shall be applied to any Resource determined to be within a constrained area in the Real-Time Energy Market.

III.A.5.5.5.2. Conduct Test.

A Resource shall fail the conduct test for constrained area commitment mitigation if the Low Load Cost at Offer divided by the Low Load Cost at Reference Level is greater than 1.25.

III.A.5.5.5.3. Consequence of Failing Test.

If a Supply Offer fails the constrained area commitment conduct test, then all financial parameters of its Supply Offer are set to their Reference Levels.

III.A.5.5.6. Reliability Commitment Mitigation.

III.A.5.5.6.1. Applicability.

Mitigation pursuant to this section shall be applied to Supply Offers for Resources that are (a) committed to provide, or Resources that are required to remain online to provide, one or more of the following:

i. local first contingency;
ii. local second contingency;
iii. VAR or voltage;
iv. distribution (Special Constraint Resource Service);
v. dual fuel resource auditing;

(b) otherwise manually committed by the ISO for reasons other than meeting anticipated load plus reserve requirements.

III.A.5.5.6.2. Conduct Test.

A Supply Offer shall fail the conduct test for local reliability commitment mitigation if the Low Load Cost at Offer divided by the Low Load Cost at Reference Level is greater than 1.10.

III.A.5.5.6.3. Consequence of Failing Test.

If a Supply Offer fails the local reliability commitment conduct test, it shall be evaluated for commitment based on an offer with all financial parameters set to their Reference Levels. This includes all offer blocks and all types of Start-Up Fees and the No-Load Fee. If a Resource is committed, then all financial parameters of its Supply Offer are set to their Reference Level.

III.A.5.5.7. Start-Up Fee and No-Load Fee Mitigation.

III.A.5.5.7.1. Applicability.

Mitigation pursuant to this section shall be applied to any Supply Offer submitted in the Day-Ahead Energy Market or Real-Time Energy Market if the resource is committed.

III.A.5.5.7.2. Conduct Test.

A Supply Offer shall fail the conduct test for Start-Up Fee and No-Load Fee mitigation if its Start-Up Fee or No-Load Fee divided by the Reference Level for that fee is greater than 3.

III.A.5.5.7.3. Consequence of Failing Conduct Test.

If a Supply Offer fails the conduct test, then all financial parameters of its Supply Offer shall be set to their Reference Levels.

III.A.5.5.8. Low Load Cost.

Low Load Cost, which is the cost of operating the Resource at its Economic Minimum Limit, is calculated as the sum of:

(a) If the Resource is starting from an offline state, the Start-Up Fee;

(b) The sum of the No Load Fees for the Commitment Period; and

(c) The sum of the hourly values resulting from the multiplication of the price of energy at the Resource's Economic Minimum Limit times its Economic Minimum Limit, for each hour of the Commitment Period.

All Supply Offer parameter values used in calculating the Low Load Cost are the values in place at the time the commitment decision is made.

Low Load Cost at Offer equals the Low Load Cost calculated with financial parameters of the Supply Offer as submitted by the Lead Market Participant.

Low Load Cost at Reference Level equals the Low Load Cost calculated with the financial parameters of the Supply Offer set to Reference Levels.

For Low Load Cost at Offer, the price of energy is the energy price parameter of the Resource's Supply Offer at the Economic Minimum Limit offer block. For Low Load Cost at Reference Level, the price of energy is the energy price parameter of the Resource's Reference Level at the Economic Minimum Limit offer block.

III.A.5.6. Duration of Energy Threshold Mitigation.

Any mitigation imposed pursuant to Sections III.A.5.5.1 “General Threshold Energy Mitigation” or III.A.5.5.2 “Constrained Area Energy Mitigation” is in effect for the following duration:

(a) in the Real-Time Energy Market, mitigation starts when the impact test violation occurs and remains in effect until there is one complete hour in which:

   i. for general threshold mitigation, the Market Participant whose Supply Offer is subject to mitigation is not a pivotal supplier; or,

   ii. for constrained area energy mitigation, the Resource is not located within a constrained area.

(b) in the Day-Ahead Energy Market (applicable only for Section III.A.5.5.2 “Constrained Area Energy Mitigation”), mitigation is in effect in each hour in which the impact test is violated.

Any mitigation imposed pursuant to Section III.A.5.5.3 “Manual Dispatch Energy Mitigation” is in effect for at least one hour until the earlier of either (a) the hour when manual dispatch is no longer in effect and the Resource returns to its Economic Minimum Limit, or (b) the hour when the energy price parameter of its Supply Offer at the Desired Dispatch Point is no longer greater than the Real-Time Price at the Resource’s Node.

III.A.5.7. Duration of Commitment Mitigation.

Any mitigation imposed pursuant to Sections III.A.5.5.4 “General Threshold Commitment Mitigation”, III.A.5.5.5 “Constrained Area Commitment Mitigation”, or III.A.5.5.6 “Reliability Commitment Mitigation” is in effect for the duration of the Commitment Period.

III.A.5.8. Duration of Start-Up Fee and No-Load Fee Mitigation.

Any mitigation imposed pursuant to Sections III.A.5.5.7 “Start-Up Fee and No-Load Fee Mitigation” is in effect for any hour in which the Supply Offer fails the conduct test in Section III.A.5.5.7.2.

III.A.5.9. Correction of Mitigation.

If the Internal Market Monitor determines that there are one or more errors in the mitigation applied in an Operating Day due to data entry, system or software errors by the ISO or the Internal Market Monitor, the Internal Market Monitor shall notify the market monitoring contacts specified by the Lead Market Participant within five Business Days of the applicable Operating Day. The ISO shall correct the error as

part of the Data Reconciliation Process by applying the correct values to the relevant Supply Offer in the settlement process.

The permissibility of correction of errors in mitigation, and the timeframes and procedures for permitted corrections, are addressed solely in this section and not in those sections of Market Rule 1 relating to settlement and billing processes.

III.A.5.10. Delay of Day-Ahead Energy Market Due to Mitigation Process.

The posting of the Day-Ahead Energy Market results may be delayed if necessary for the completion of mitigation procedures.

III.A.6. Physical and Financial Parameter Offer Thresholds.

Physical parameters of a Supply Offer are limited to thresholds specified in this section. Physical parameters are limited by the software accepting offers, except those that can be re-declared in real time during the Operating Day. Parameters that exceed the thresholds specified here but are not limited through the software accepting offers are subject to Internal Market Monitor review after the Operating Day and possible referral to the Commission under Section III.A.19 of this Appendix.

III.A.6.1. Time-Based Offer Parameters.

Supply Offer parameters that are expressed in time (i.e., Minimum Run Time, Minimum Down Time, Start-Up Time, and Notification Time) shall have a threshold of two hours for an individual parameter or six hours for the combination of the time-based offer parameters compared to the Resource's Reference Levels. Offers may not exceed these thresholds in a manner that reduce the flexibility of the Resource. To determine if the six hour threshold is exceeded, all time-based offer parameters will be summed for each start-up state (hot, intermediate and cold). If the sum of the time-based offer parameters for a start-up state exceeds six hours above the sum of the Reference Levels for those offer parameters, then the six hour threshold is exceeded.

III.A.6.2. Financial Offer Parameters.

The Start-Up Fee and the No-Load Fee values of a Resource's Supply Offer may be no greater than three times the Start-Up Fee and No-Load Fee Reference Level values for the Resource. In the event a fuel price has been submitted under Section III.A.3.4, the Start-Up Fee and No-Load Fee for the associated Supply Offer shall be limited in a Real-Time Offer Change. The limit shall be the percent increase in the new fuel price, relative to the fuel price otherwise used by the Internal Market Monitor, multiplied by the

Start-Up Fee or No-Load Fee from the Re-Offer Period. Absent a fuel price adjustment, a Start-Up Fee or No-Load Fee may be changed in a Real-Time Offer Change to no more than the Start-Up Fee and No-Load Fee values submitted for the Re-Offer Period.

III.A.6.3. Other Offer Parameters.

Non-financial or non-time-based offer parameters shall have a threshold of a 100% increase, or greater, for parameters that are minimum values, or a 50% decrease, or greater, for parameters that are maximum values (including, but not limited to, ramp rates, Economic Maximum Limits and maximum starts per day) compared to the Resource's Reference Levels.

Offer parameters that are limited by performance caps or audit values imposed by the ISO are not subject to the provisions of this section.

III.A.7. Calculation of Resource Reference Levels for Physical Parameters and Financial Parameters of Resources.

Market Participants are responsible for providing the Internal Market Monitor with all the information and data necessary for the Internal Market Monitor to calculate up-to-date Reference Levels for each of a Market Participant's Resources.

III.A.7.1. Methods for Determining Reference Levels for Physical Parameters.

The Internal Market Monitor will calculate a Reference Level for each element of a bid or offer that is expressed in units other than dollars (such as time-based or quantity level bid or offer parameters) on the basis of one or more of the following:

(a) Original equipment manufacturer (OEM) operating recommendations and performance data for all Resource types in the New England Control Area, grouped by unit classes, physical parameters and fuel types.

(b) Applicable environmental operating permit information currently on file with the issuing environmental regulatory body.

(c) Verifiable Resource physical operating characteristic data, including but not limited to facility and/or Resource operating guides and procedures, historical operating data and any verifiable documentation related to the Resource, which will be reviewed in consultation with the Market Participant.

III.A.7.2. Methods for Determining Reference Levels for Financial Parameters of Offers.

The Reference Levels for Start-Up Fees, No-Load Fees, Interruption Costs and offer blocks will be calculated separately and assuming no costs from one component are included in another component.

III.A.7.2.1. Order of Reference Level Calculation.

The Internal Market Monitor will calculate a Reference Level for each offer block of an offer according to the following hierarchy, under which the first method that can be calculated is used:

(a) accepted offer-based Reference Levels pursuant to Section III.A.7.3;
(b) LMP-based Reference Levels pursuant to Section III.A.7.4; and,
(c) cost-based Reference Levels pursuant to Section III.A.7.5.

III.A.7.2.2. Circumstances in Which Cost-Based Reference Levels Supersede the Hierarchy of Reference Level Calculation.

In the following circumstances, cost-based Reference Levels shall be used notwithstanding the hierarchy specified in Section III.A.7.2.1.

(a) When in any hour the cost-based Reference Level is higher than either the accepted offer-based or LMP-based Reference Level.
(b) When the Supply Offer parameter is a Start-Up Fee or the No-Load Fee.
(c) For any Operating Day for which the Lead Market Participant requests the cost-based Reference Level.
(d) For any Operating Day for which, during the previous 90 days:
  (i) the Resource has been flagged for VAR, SCR, or as a Local Second Contingency Protection Resource for any hour in the Day-Ahead Energy Market or the Real-Time Energy Market, and;
  (ii) the ratio of the sum of the operating hours for days for which the Resource has been flagged during the previous 90 days in which the number of hours operated out of economic merit order in the Day-Ahead Energy Market and the Real-Time Energy Market exceed the number of hours operated in economic merit order in the Day-Ahead Energy Market and Real-Time Energy Market, to the total number of operating hours in the Day-Ahead Energy Market and Real-Time Energy Market during the previous 90 days is greater than or equal to 50 percent.
(e) When in any hour the incremental energy parameter of an offer, including adjusted offers pursuant to Section III.2.4, is greater than $1,000/MWh.

For the purposes of this subsection:

i. A flagged day is any day in which the Resource has been flagged for VAR, SCR, or as a Local Second Contingency Protection Resource for any hour in either the Day-Ahead Energy Market or the Real-Time Energy Market.

ii. Operating hours are the hours in the Day-Ahead Energy Market for which a Resource has cleared output (MW) greater than zero and hours in the Real-Time Energy Market for which a Resource has metered output (MW) greater than zero. For days for which Real-time Energy Market metered values are not yet available in the ISO's or the Internal Market Monitor's systems, telemetered values will be used.

iii. Self-scheduled hours will be excluded from all of the calculations described in this subsection, including the determination of operating hours.

iv. The determination as to whether a Resource operated in economic merit order during an hour will be based on the energy offer block within which the Resource is operating.

(e) The Market Participant submits a fuel price pursuant to Section III.A.3.4. When the Market Participant submits a fuel price for any hour of a Supply Offer in the Day-Ahead Energy Market or Re-Offer Period, then the cost-based Reference Level is used for the entire Operating Day. If a fuel price is submitted for a Supply Offer after the close of the Re-Offer Period for the next Operating Day or for the current Operating Day, then the cost-based Reference Level for the Supply Offer is used from the time of the submittal to the end of the Operating Day.

(f) When the Market Participant submits a change to any of the following parameters of the Supply Offer after the close of the Re-Offer Period:

(i) hot, intermediate, or cold Start-Up Fee, or a corresponding fuel blend,

(ii) No-Load Fee or its corresponding fuel blends,

(iii) whether to include the Start-Up Fee and No-Load Fee in the Supply Offer,

(iv) the quantity or price value of any Block in the Supply Offer or its corresponding fuel blends, and

(v) whether to use the offer slope for the Supply Offer,

then, the cost-based Reference Level for the Supply Offer will be used from the time of the submittal to the end of the Operating Day.

III.A.7.3. Accepted Offer-Based Reference Level.

The Internal Market Monitor shall calculate the accepted offer-based Reference Level as the lower of the mean or the median of a generating Resource's Supply Offers that have been accepted and are part of the seller's Day-Ahead Generation Obligation or Real-Time Generation Obligation in competitive periods over the previous 90 days, adjusted for changes in fuel prices utilizing fuel indices generally applicable for the location and type of Resource. For purposes of this section, a competitive period is an Operating Day in which the Resource is scheduled in economic merit order.

III.A.7.4. LMP-Based Reference Level.

The Internal Market Monitor shall calculate the LMP-based Reference Level as the mean of the LMP at the Resource's Node during the lowest-priced 25% of the hours that the Resource was dispatched over the previous 90 days for similar hours (on-peak or off-peak), adjusted for changes in fuel prices.

III.A.7.5. Cost-Based Reference Level.

The Internal Market Monitor shall calculate cost-based Reference Levels taking into account information on costs provided by the Market Participant though the consultation process prescribed in Section III.A.3.

The following criteria shall be applied to estimates of cost:

(a) The provision of cost estimates by a Market Participant shall conform with the timing and requirements of Section III.A.3 "Consultation Prior to Determination of Reference Levels for Physical and Financial Parameters of Resources".
(b) Costs must be documented.
(c) All cost estimates shall be based on estimates of current market prices or replacement costs and not inventory costs wherever possible. All cost estimates, including opportunity cost estimates, must be quantified and analytically supported.
(d) When market prices or replacement costs are unavailable, cost estimates shall identify whether the reported costs are the result of a product or service provided by an Affiliate of the Market Participant.
(e) The Internal Market Monitor will evaluate cost information provided by the Market Participant in comparison to other information available to the Internal Market Monitor. Reference Levels associated with Resources for which a fuel price has been submitted under Section III.A.3.4 shall be calculated using the lower of the submitted fuel price or a price, calculated by the Internal Market Monitor, that takes account of the following factors and conditions:

i. Fuel market conditions, including the current spread between bids and asks for current fuel delivery, fuel trading volumes, near-term price quotes for fuel, expected natural gas heating demand, and Market Participant-reported quotes for trading and fuel costs; and

ii. Fuel delivery conditions, including current and forecasted fuel delivery constraints and current line pack levels for natural gas pipelines.

III.A.7.5.1. Estimation of Incremental Operating Cost.

The Internal Market Monitor's determination of a Resource's marginal costs shall include an assessment of the Resource's incremental operating costs in accordance with the following formulas,

Incremental Energy/Reduction:

(incremental heat rate * fuel costs) + (emissions rate * emissions allowance price) + variable operating and maintenance costs + opportunity costs.

Opportunity costs may include, but are not limited to, economic costs associated with complying with:

(a) emissions limits;

(b) water storage limits;

(c) other operating permits that limit production of energy; and

(d) reducing electricity consumption.

No-Load:

(no-load fuel use * fuel costs) + (no-load emissions * emission allowance price) + no-load variable operating and maintenance costs + other no-load costs that are not fuel, emissions or variable and maintenance costs.

Start-Up/Interruption:

(start-up fuel use * fuel costs) + (start-up emissions * emission allowance price) + start-up variable and maintenance costs + other start-up costs that are not fuel, emissions or variable and maintenance costs.

III.A.8. [Reserved.]

III.A.9. Regulation.

The Internal Market Monitor will monitor the Regulation market for conduct that it determines constitutes an abuse of market power. If the Internal Market Monitor identifies any such conduct, it may make a filing under Section 205 of the Federal Power Act with the Commission requesting authorization to apply appropriate mitigation measures or to revise Market Rule 1 to address such conduct (or both). The Internal Market Monitor may make such a filing at any time it deems necessary, and may request expedited treatment from the Commission. Any such filing shall identify the particular conduct the Internal Market Monitor believes warrants mitigation or revisions to Market Rule 1 (or both), shall propose a specific mitigation measure for the conduct or revision to Market Rule 1 (or both), and shall set forth the Internal Market Monitor's justification for imposing that mitigation measure or revision to Market Rule 1 (or both).

III.A.10. Demand Bids.

The Internal Market Monitor will monitor the Energy Market as outlined below:

(a) LMPs in the Day-Ahead Energy Market and Real-Time Energy Market shall be monitored to determine whether there is a persistent hourly deviation in any location that would not be expected in a workably competitive market.

(b) The Internal Market Monitor shall compute the average hourly deviation between Day-Ahead Energy Market and Real-Time Energy Market LMPs, measured as: $(LMP_{\text{real time}} / LMP_{\text{day ahead}}) - 1$. The average hourly deviation shall be computed over a rolling four-week period or such other period determined by the Internal Market Monitor.

(c) The Internal Market Monitor shall estimate and monitor the average percentage of each Market Participant's bid to serve load scheduled in the Day-Ahead Energy Market, using a methodology intended to identify a sustained pattern of under-bidding as accurately as deemed practicable. The average percentage will be computed over a specified time period determined by the Internal Market Monitor.

If the Internal Market Monitor determines that: (i) The average hourly deviation is greater than ten percent (10%) or less than negative ten percent (-10%), (ii) one or more Market Participants on behalf of one or more LSEs have been purchasing a substantial portion of their loads with purchases in the Real-Time Energy Market, (iii) this practice has contributed to an unwarranted divergence of LMPs between

the two markets, and (iv) this practice has created operational problems, the Internal Market Monitor may make a filing under Section 205 of the Federal Power Act with the Commission requesting authorization to apply appropriate mitigation measures or to revise Market Rule 1 to address such conduct (or both). The thresholds identified above shall not limit the Internal Market Monitor's authority to make such a filing. The Internal Market Monitor may make such a filing at any time it deems necessary, and may request expedited treatment from the Commission. Any such filing shall identify the particular conduct that the Internal Market Monitor believes warrants mitigation or revisions to Market Rule 1 (or both), shall propose a specific mitigation measure for the conduct or revision to Market Rule 1 (or both), and shall set forth the Internal Market Monitor's justification for imposing that mitigation measure or revision to Market Rule 1 (or both).

III.A.11. Mitigation of Increment Offers and Decrement Bids.

III.A.11.1. Purpose.

The provisions of this section specify the market monitoring and mitigation measures applicable to Increment Offers and Decrement Bids. An Increment Offer is one to supply energy and a Decrement Bid is one to purchase energy, in either such case not being backed by physical load or generation and submitted in the Day-Ahead Energy Market in accordance with the procedures and requirements specified in Market Rule 1 and the ISO New England Manuals.

III.A.11.2. Implementation.

III.A.11.2.1. Monitoring of Increment Offers and Decrement Bids.

Day-Ahead LMPs and Real-Time LMPs in each Load Zone or Node, as applicable, shall be monitored to determine whether there is a persistent hourly deviation in the LMPs that would not be expected in a workably competitive market. The Internal Market Monitor shall compute the average hourly deviation between Day-Ahead LMPs and Real-Time LMPs, measured as:

$(LMP_{\text{real time}} / LMP_{\text{day ahead}}) - 1.$

The average hourly deviation shall be computed over a rolling four-week period or such other period determined by the Internal Market Monitor to be appropriate to achieve the purpose of this mitigation measure.

III.A.11.3. Mitigation Measures.

If the Internal Market Monitor determines that (i) the average hourly deviation computed over a rolling four week period is greater than ten percent (10%) or less than negative ten percent (-10%), and (ii) the bid and offer practices of one or more Market Participants has contributed to a divergence between LMPs in the Day-Ahead Energy Market and Real-Time Energy Market, then the following mitigation measure may be imposed:

The Internal Market Monitor may limit the hourly quantities of Increment Offers for supply or Decrement Bids for load that may be offered in a Location by a Market Participant, subject to the following provisions:

(i) The Internal Market Monitor shall, when practicable, request explanations of the relevant bid and offer practices from any Market Participant submitting such bids.

(ii) Prior to imposing a mitigation measure, the Internal Market Monitor shall notify the affected Market Participant of the limitation.

(iii) The Internal Market Monitor, with the assistance of the ISO, will restrict the Market Participant for a period of six months from submitting any virtual transactions at the same Node(s), and/or electrically similar Nodes to, the Nodes where it had submitted the virtual transactions that contributed to the unwarranted divergence between the LMPs in the Day-Ahead Energy Market and Real-Time Energy Market.

III.A.11.4. Monitoring and Analysis of Market Design and Rules.

The Internal Market Monitor shall monitor and assess the impact of Increment Offers and Decrement Bids on the competitive structure and performance, and the economic efficiency of the New England Markets. Such monitoring and assessment shall include the effects, if any, on such bids and offers of any mitigation measures specified in this Market Rule 1.

III.A.12. Cap on FTR Revenues.

If a holder of an FTR between specified delivery and receipt Locations (i) had an Increment Offer and/or Decrement Bid that was accepted by the ISO for an applicable hour in the Day-Ahead Energy Market for delivery or receipt at or near delivery or receipt Locations of the FTR; and (ii) the result of the acceptance of such Increment Offer or Decrement Bid is that the difference in LMP in the Day-Ahead Energy Market between such delivery and receipt Locations is greater than the difference in LMP between such delivery and receipt Locations in the Real-Time Energy Market, then the Market Participant shall not receive any Transmission Congestion Credit associated with such FTR in such hour, in excess of one divided by the

number of hours in the applicable month multiplied by the amount originally paid for the FTR in the FTR Auction. A Location shall be considered at or near the FTR delivery or receipt Location if seventy-five % or more of the energy injected or withdrawn at that Location and which is withdrawn or injected at another Location is reflected in the constrained path between the subject FTR delivery and receipt Locations that were acquired in the FTR Auction.

III.A.13. Additional Internal Market Monitor Functions Specified in Tariff.

III.A.13.1. Review of Offers and Bids in the Forward Capacity Market.

In accordance with the following provisions of Section III.13 of Market Rule 1, the Internal Market Monitor is responsible for reviewing certain bids and offers made in the Forward Capacity Market. Section III.13 of Market Rule 1 specifies the nature and detail of the Internal Market Monitor's review and the consequences that will result from the Internal Market Monitor's determination following such review.

(a) [Reserved].

(b) Section III.13.1.2.3.1.6.3 - Internal Market Monitor review of Static De-List Bids, Permanent De-List Bids, and Retirement De-List Bids from an Existing Generating Capacity Resource that is associated with a Station having Common Costs.

(c) Section III.13.1.2.3.2 - Review by Internal Market Monitor of Bids from Existing Generating Capacity Resources.

(d) Section III.13.1.3.3A(d) - Review by Internal Market Monitor of offers from Existing Import Capacity Resources.

(e) Section III.13.1.3.5.6 - Review by Internal Market Monitor of Offers from New Import Capacity Resources.

(f) Section III.13.1.7 - Internal Market Monitor review of summer and winter Seasonal Claimed Capability values.

III.A.13.2. Supply Offers and Demand Bids Submitted for Reconfiguration Auctions in the Forward Capacity Market.

Section III.13.4 of Market Rule 1 addresses reconfiguration auctions in the Forward Capacity Market. As addressed in Section III.13.4.2 of Market Rule 1, a supply offer or demand bid submitted for a reconfiguration auction shall not be subject to mitigation by the Internal Market Monitor.

III.A.13.3. Monitoring of Transmission Facility Outage Scheduling.

Appendix G of Market Rule 1 addresses the scheduling of outages for transmission facilities. The Internal Market Monitor shall monitor the outage scheduling activities of the Transmission Owners. The Internal Market Monitor shall have the right to request that each Transmission Owner provide information to the Internal Market Monitor concerning the Transmission Owner's scheduling of transmission facility outages, including the repositioning or cancellation of any interim approved or approved outage, and the Transmission Owner shall provide such information to the Internal Market Monitor in accordance with the ISO New England Information Policy.

III.A.13.4. Monitoring of Forward Reserve Resources.

The Internal Market Monitor will receive information that will identify Forward Reserve Resources, the Forward Reserve Threshold Price, and the assigned Forward Reserve Obligation. Prior to mitigation of Supply Offers or Demand Bids associated with a Forward Reserve Resource, the Internal Market Monitor shall consult with the Market Participant in accordance with Section III.A.3 of this ***Appendix A***. The Internal Market Monitor and the Market Participant shall consider the impact on meeting any Forward Reserve Obligations in those consultations. If mitigation is imposed, any mitigated offers shall be used in the calculation of qualifying megawatts under Section III.9.6.4 of Market Rule 1.

III.A.13.5. Imposition of Sanctions.

Appendix B of Market Rule 1 sets forth the procedures and standards under which sanctions may be imposed for certain violations of Market Participants' obligations under the ISO New England Filed Documents and other ISO New England System Rules. The Internal Market Monitor shall administer ***Appendix B*** in accordance with the provisions thereof.

III.A.14. Treatment of Supply Offers for Resources Subject to a Cost-of-Service Agreement.

Article 5 of the form of Cost-of-Service Agreement in ***Appendix I*** to Market Rule 1 addresses the monitoring of resources subject to a cost-of-service agreement by the Internal Market Monitor and External Market Monitor. Pursuant to Section 5.2 of Article 5 of the Form of Cost-of-Service Agreement, after consultation with the Lead Market Participant, Supply Offers that exceed Stipulated Variable Cost as determined in the agreement are subject to adjustment by the Internal Market Monitor to Stipulated Variable Cost.

III.A.15. Request for Additional Cost Recovery.

III.A.15.1. Cost Recovery Request Following Capping.

If as a result of an offer being capped under Section III.1.9, a Market Participant believes that it will not recover the fuel and variable operating and maintenance costs of the Resource, as reflected in the offer, for the hours of the Operating Day during which the offer was capped, the Market Participant may, within 20 days of the receipt of the first Invoice issued containing credits or charges for the applicable Operating Day, submit an additional cost recovery request to the Internal Market Monitor.

A request under this Section III.A.15 may seek recovery of additional costs incurred for the duration of the period of time for which the Resource was operated at the cap.

III.A.15.1.1. Timing and Contents of Request.

Within 20 days of the receipt of the first Invoice containing credits or charges for the applicable Operating Day, a Market Participant requesting additional cost recovery under this Section III.A.15.1 shall submit to the Internal Market Monitor a request in writing detailing: (i) the actual fuel and variable operating and maintenance costs for the Resource for the applicable Operating Days, with supporting data, documentation and calculations for those costs; and (ii) an explanation of why the actual costs of operating the Resource exceeded the capped costs.

III.A.15.1.2. Review by Internal Market Monitor.

To evaluate a Market Participant's request, the Internal Market Monitor shall use the data, calculations and explanations provided by the Market Participant to verify the actual fuel and variable operating and maintenance costs for the Resource for the applicable Operating Days, using the same standards and methodologies the Internal Market Monitor uses to evaluate requests to update Reference Levels under Section III.A.3 of Appendix A. To the extent the Market Participant's request warrants additional cost recovery, the Internal Market Monitor shall reflect that adjustment in the Resource's Reference Levels for the period covered by the request. The ISO shall then re-apply the cost verification and capping formulas in Section III.1.9 using the updated Reference Levels to re-calculate the adjustments to the Market Participant's offers required thereunder, and then shall calculate additional cost recovery using the adjusted offer values.

Within 20 days of the receipt of a completed submittal, the Internal Market Monitor shall provide a written response to the Market Participant's request, detailing (i) the extent to which it agrees with the request with supporting explanation, and (ii) a calculation of the additional cost recovery. Changes to

credits and charges resulting from an additional cost recovery request shall be included in the Data Reconciliation Process.

III.A.15.1.3. Cost Allocation.

The ISO shall allocate charges to Market Participants for payment of any additional cost recovery granted under this Section III.A.15.1 in accordance with the cost allocation provisions of Market Rule 1 that otherwise would apply to payments for the services provided based on the Resource's actual dispatch for the Operating Days in question.

III.A.15.2. Section 205 Filing Right.

If either

(a) as a result of mitigation applied to a Resource under this ***Appendix A*** for all or part of one or more Operating Days, or

(b) in the absence of mitigation, as a result of a request under Section III.A.15.1 being denied in whole or in part,

a Market Participant believes that it will not recover the fuel and variable operating and maintenance costs of the Resource, as reflected in the offer, for the hours of the Operating Day during which the offer was mitigated or the Section III.A.15.1 request was denied, the Market Participant may submit a filing to the Commission seeking recovery of those costs pursuant to Section 205 of the Federal Power Act. For filings to address cost recovery under Section III.A.15.2(a), the filing must be made within sixty days of receipt of the first Invoice issued containing credits or charges for the applicable Operating Day. For filings to address cost recovery under Section III.A.15.2(b), the filing must be made within sixty days of receipt of the first Invoice issued that reflects the denied request for additional cost recovery under Section III.A.15.1.

A request under this Section III.A.15.2 may seek recovery of additional costs incurred during the following periods: (a) if as a result of mitigation, costs incurred for the duration of the mitigation event, and (b) if as a result of having a Section III.A.15.1 request denied, costs incurred for the duration of the period of time addressed in the Section III.A.15.1 request.

III.A.15.2.1. Contents of Filing.

Any Section 205 filing made pursuant to this section shall include: (i) the actual fuel and variable operating and maintenance costs for the Resource for the applicable Operating Days, with supporting data

and calculations for those costs; (ii) an explanation of (a) why the actual costs of operating the Resource exceeded the Reference Level costs or, (b) in the absence of mitigation, why the actual costs of operating the Resource, as reflected in the original offer and to the extent not recovered under Section III.A.15.1, exceeded the costs as reflected in the capped offer; (iii) the Internal Market Monitor's written explanation provided pursuant to Section III.A.15.3; and (iv) all requested regulatory costs in connection with the filing.

III.A.15.2.2. Review by Internal Market Monitor Prior to Filing.

Within twenty days of the receipt of the applicable Invoice, a Market Participant that intends to make a Section 205 filing pursuant to this Section III.A.15.2 shall submit to the Internal Market Monitor the information and explanation detailed in Section III.A.15.2.1 (i) and (ii) that is to be included in the Section 205 filing. Within twenty days of the receipt of a completed submittal, the Internal Market Monitor shall provide a written explanation of the events that resulted in the Section III.A.15.2 request for additional cost recovery. The Market Participant shall include the Internal Market Monitor's written explanation in the Section 205 filing made pursuant to this Section III A.15.2.

III.A.15.2.3. Cost Allocation.

In the event that the Commission accepts a Market Participant's filing for cost recovery under this section, the ISO shall allocate charges to Market Participants for payment of those costs in accordance with the cost allocation provisions of Market Rule 1 that otherwise would apply to payments for the services provided based on the Resource's actual dispatch for the Operating Days in question.

III.A.16. ADR Review of Internal Market Monitor Mitigation Actions.

III.A.16.1. Actions Subject to Review.

A Market Participant may obtain prompt Alternative Dispute Resolution ("ADR") review of any Internal Market Monitor mitigation imposed on a Resource as to which that Market Participant has bidding or operational authority. A Market Participant must seek review pursuant to the procedure set forth in ***Appendix D*** to this Market Rule 1, but in all cases within the time limits applicable to billing adjustment requests. These deadlines are currently specified in the ISO New England Manuals. Actions subject to review are:

- Imposition of a mitigation remedy.

- Continuation of a mitigation remedy as to which a Market Participant has submitted material evidence of changed facts or circumstances. (Thus, after a Market Participant has unsuccessfully challenged imposition of a mitigation remedy, it may challenge the continuation of that mitigation in a subsequent ADR review on a showing of material evidence of changed facts or circumstances.)

III.A.16.2. Standard of Review.

On the basis of the written record and the presentations of the Internal Market Monitor and the Market Participant, the ADR Neutral shall review the facts and circumstances upon which the Internal Market Monitor based its decision and the remedy imposed by the Internal Market Monitor. The ADR Neutral shall remove the Internal Market Monitor's mitigation only if it concludes that the Internal Market Monitor's application of the Internal Market Monitor mitigation policy was clearly erroneous. In considering the reasonableness of the Internal Market Monitor's action, the ADR Neutral shall consider whether adequate opportunity was given to the Market Participant to present information, any voluntary remedies proposed by the Market Participant, and the need of the Internal Market Monitor to act quickly to preserve competitive markets.

III.A.17. Reporting.

III.A.17.1. Data Collection and Retention.

Market Participants shall provide the Internal Market Monitor and External Market Monitor with any and all information within their custody or control that the Internal Market Monitor or External Market Monitor deems necessary to perform its obligations under this ***Appendix A***, subject to applicable confidentiality limitations contained in the ISO New England Information Policy. This would include a Market Participant's cost information if the Internal Market Monitor or External Market Monitor deems it necessary, including start up, no-load and all other actual marginal costs, when needed for monitoring or mitigation of that Market Participant. Additional data requirements may be specified in the ISO New England Manuals. If for any reason the requested explanation or data is unavailable, the Internal Market Monitor and External Market Monitor will use the best information available in carrying out their responsibilities. The Internal Market Monitor and External Market Monitor may use any and all information they receive in the course of carrying out their market monitor and mitigation functions to the extent necessary to fully perform those functions.

Market Participants must provide data and any other information requested by the Internal Market Monitor that the Internal Market Monitor requests to determine:

(a) the opportunity costs associated with Demand Reduction Offers;

(b) the accuracy of Demand Response Baselines;

(c) the method used to achieve a demand reduction, and;

(d) the accuracy of metered demand reported to the ISO.

III.A.17.2. Periodic Reporting by the ISO and Internal Market Monitor.

III.A.17.2.1. Monthly Report.

The ISO will prepare a monthly report, which will be available to the public both in printed form and electronically, containing an overview of the market's performance in the most recent period.

III.A.17.2.2. Quarterly Report.

The Internal Market Monitor will prepare a quarterly report consisting of market data regularly collected by the Internal Market Monitor in the course of carrying out its functions under this ***Appendix A*** and analysis of such market data. Final versions of such reports shall be disseminated contemporaneously to the Commission, the ISO Board of Directors, the Market Participants, and state public utility commissions for each of the six New England states, provided that in the case of the Market Participants and public utility commissions, such information shall be redacted as necessary to comply with the ISO New England Information Policy. The format and content of the quarterly reports will be updated periodically through consensus of the Internal Market Monitor, the Commission, the ISO, the public utility commissions of the six New England States and Market Participants. The entire quarterly report will be subject to confidentiality protection consistent with the ISO New England Information Policy and the recipients will ensure the confidentiality of the information in accordance with state and federal laws and regulations. The Internal Market Monitor will make available to the public a redacted version of such quarterly reports. The Internal Market Monitor, subject to confidentiality restrictions, may decide whether and to what extent to share drafts of any report or portions thereof with the Commission, the ISO, one or more state public utility commission(s) in New England or Market Participants for input and verification before the report is finalized. The Internal Market Monitor shall keep the Market Participants informed of the progress of any report being prepared pursuant to the terms of this ***Appendix A.***

III.A.17.2.3. Reporting on General Performance of the Forward Capacity Market.

The performance of the Forward Capacity Market, including reconfiguration auctions, shall be subject to the review of the Internal Market Monitor. No later than 180 days after the completion of the second Forward Capacity Auction, the Internal Market Monitor shall file with the Commission and post to the ISO's website a full report analyzing the operations and effectiveness of the Forward Capacity Market. Thereafter, the Internal Market Monitor shall report on the functioning of the Forward Capacity Market in its annual markets report in accordance with the provisions of Section III.A.17.2.4 of this ***Appendix A***.

III.A.17.2.4. Annual Review and Report by the Internal Market Monitor.

The Internal Market Monitor will prepare an annual state of the market report on market trends and the performance of the New England Markets and will present an annual review of the operations of the New England Markets. The annual report and review will include an evaluation of the procedures for the determination of energy, reserve and regulation clearing prices, NCPC costs and the performance of the Forward Capacity Market and FTR Auctions. The review will include a public forum to discuss the performance of the New England Markets, the state of competition, and the ISO's priorities for the coming year. In addition, the Internal Market Monitor will arrange a non-public meeting open to appropriate state or federal government agencies, including the Commission and state regulatory bodies, attorneys general, and others with jurisdiction over the competitive operation of electric power markets, subject to the confidentiality protections of the ISO New England Information Policy, to the greatest extent permitted by law.

III.A.17.2.5. Additional Ad Hoc Reporting on Performance and Competiveness of Markets

Commencing on June 1, 2024, in furtherance of its functions under Section III.A.2 of this Appendix A, including without limitation Sections III.A.2.3 (e) and (k) therein, the Internal Market Monitor shall perform independent evaluations and prepare ad hoc reports on the overall competitiveness and performance of the New England Markets or particular aspects of the New England Markets, including the competitiveness and performance of a major market design change. The Internal Market Monitor shall have the sole discretion to determine when to prepare an ad hoc report and may prepare such report on its own initiative or pursuant to a request by the ISO, New England state public utility commissions or one or more Market Participants. However, the Internal Market Monitor will report on the competitiveness and performance of any new major market design change within one to three years, respectively, of the effective date of

operation of the market design change, or as soon as adequate data becomes available. While the Internal Market Monitor may solicit and/or receive input of the External Market Monitor, Market Participants and other stakeholders, including New England state public utility commissions, the methodology and criteria used to conduct its independent analysis shall be at the sole discretion of the Internal Market Monitor. The Internal Market Monitor shall describe its methodology and criteria used in an ad hoc report of its significant findings and, if any, recommendations. The Internal Market Monitor shall file with the Commission and post to the ISO's website a final version of an ad hoc report. Thereafter, the Internal Market Monitor shall continue to report on the competitiveness and performance of any market design change that has been the subject of an ad hoc report in its quarterly and/or annual reports under Sections III.A.17.2.2 and III.A.17.2.4.

III.A.17.3. Periodic Reporting by the External Market Monitor.

The External Market Monitor will perform independent evaluations and prepare annual and ad hoc reports on the overall competitiveness and efficiency of the New England Markets or particular aspects of the New England Markets, including the adequacy of ***Appendix A***. The External Market Monitor shall have the sole discretion to determine whether and when to prepare ad hoc reports and may prepare such reports on its own initiative or pursuant to requests by the ISO, state public utility commissions or one or more Market Participants. Final versions of such reports shall be disseminated contemporaneously to the Commission, the ISO Board of Directors, the Market Participants, and state public utility commissions for each of the six New England states, provided that in the case of the Market Participants and public utility commissions, such information shall be redacted as necessary to comply with the ISO New England Information Policy. Such reports shall, at a minimum, include:

(i) Review and assessment of the practices, market rules, procedures, protocols and other activities of the ISO insofar as such activities, and the manner in which the ISO implements such activities, affect the competitiveness and efficiency of New England Markets.

(ii) Review and assessment of the practices, procedures, protocols and other activities of any independent transmission company, transmission provider or similar entity insofar as its activities affect the competitiveness and efficiency of the New England Markets.

(iii) Review and assessment of the activities of Market Participants insofar as these activities affect the competitiveness and efficiency of the New England Markets.

(iv) Review and assessment of the effectiveness of ***Appendix A*** and the administration of ***Appendix A*** by the Internal Market Monitor for consistency and compliance with the terms of ***Appendix A.***

(v) Review and assessment of the relationship of the New England Markets with any independent transmission company and with adjacent markets.

The External Market Monitor, subject to confidentiality restrictions, may decide whether and to what extent to share drafts of any report or portions thereof with the Commission, the ISO, one or more state public utility commission(s) in New England or Market Participants for input and verification before the report is finalized. The External Market Monitor shall keep the Market Participants informed of the progress of any report being prepared.

III.A.17.4. Other Internal Market Monitor or External Market Monitor Communications With Government Agencies.

III.A.17.4.1. Routine Communications.

The periodic reviews are in addition to any routine communications the Internal Market Monitor or External Market Monitor may have with appropriate state or federal government agencies, including the Commission and state regulatory bodies, attorneys general, and others with jurisdiction over the competitive operation of electric power markets.

III.A.17.4.2. Additional Communications.

The Internal Market Monitor and External Market Monitor are not a regulatory or enforcement agency. However, they will monitor market trends, including changes in Resource ownership as well as market performance. In addition to the information on market performance and mitigation provided in the monthly, quarterly and annual reports the External Market Monitor or Internal Market Monitor shall:

(a) Inform the jurisdictional state and federal regulatory agencies, as well as the Markets Committee, if the External Market Monitor or Internal Market Monitor determines that a market problem appears to be developing that will not be adequately remediable by existing market rules or mitigation measures;

(b) If the External Market Monitor or Internal Market Monitor receives information from any entity regarding an alleged violation of law, refer the entity to the appropriate state or federal agencies;

(c) If the External Market Monitor or Internal Market Monitor reasonably concludes, in the normal course of carrying out its monitoring and mitigation responsibilities, that certain

market conduct constitutes a violation of law, report these matters to the appropriate state and federal agencies; and,

(d) Provide the names of any companies subjected to mitigation under these procedures as well as a description of the behaviors subjected to mitigation and any mitigation remedies or sanctions applied.

III.A.17.4.3. Confidentiality.

Information identifying particular participants required or permitted to be disclosed to jurisdictional bodies under this section shall be provided in a confidential report filed under Section 388.112 of the Commission regulations and corresponding provisions of other jurisdictional agencies. The Internal Market Monitor will include the confidential report with the quarterly submission it provides to the Commission pursuant to Section III.A.17.2.2.

III.A.17.5. Other Information Available from Internal Market Monitor and External Market Monitor on Request by Regulators.

The Internal Market Monitor and External Market Monitor will normally make their records available as described in this paragraph to authorized state or federal agencies, including the Commission and state regulatory bodies, attorneys general and others with jurisdiction over the competitive operation of electric power markets ("authorized government agencies"). With respect to state regulatory bodies and state attorneys general ("authorized state agencies"), the Internal Market Monitor and External Market Monitor shall entertain information requests for information regarding general market trends and the performance of the New England Markets, but shall not entertain requests that are designed to aid enforcement actions of a state agency. The Internal Market Monitor and External Market Monitor shall promptly make available all requested data and information that they are permitted to disclose to authorized government agencies under the ISO New England Information Policy. Notwithstanding the foregoing, in the event an information request is unduly burdensome in terms of the demands it places on the time and/or resources of the Internal Market Monitor or External Market Monitor, the Internal Market Monitor or External Market Monitor shall work with the authorized government agency to modify the scope of the request or the time within which a response is required, and shall respond to the modified request.

The Internal Market Monitor and External Market Monitor also will comply with compulsory process, after first notifying the owner(s) of the items and information called for by the subpoena or civil investigative demand and giving them at least ten Business Days to seek to modify or quash the compulsory process. If an authorized government agency makes a request in writing, other than

compulsory process, for information or data whose disclosure to authorized government agencies is not permitted by the ISO New England Information Policy, the Internal Market Monitor and External Market Monitor shall notify each party with an interest in the confidentiality of the information and shall process the request under the applicable provisions of the ISO New England Information Policy. Requests from the Commission for information or data whose disclosure is not permitted by the ISO New England Information Policy shall be processed under Section 3.2 of the ISO New England Information Policy. Requests from authorized state agencies for information or data whose disclosure is not permitted by the ISO New England Information Policy shall be processed under Section 3.3 of the ISO New England Information Policy. In the event confidential information is ultimately released to an authorized state agency in accordance with Section 3.3 of the ISO New England Information Policy, any party with an interest in the confidentiality of the information shall be permitted to contest the factual content of the information, or to provide context to such information, through a written statement provided to the Internal Market Monitor or External Market Monitor and the authorized state agency that has received the information.

III.A.18. Ethical Conduct Standards.

III.A.18.1. Compliance with ISO New England Inc. Code of Conduct.
The employees of the ISO that perform market monitoring and mitigation services for the ISO and the employees of the External Market Monitor that perform market monitoring and mitigation services for the ISO shall execute and shall comply with the terms of the ISO New England Inc. Code of Conduct attached hereto as ***Exhibit 5***.

III.A.18.2. Additional Ethical Conduct Standards.
The employees of the ISO that perform market monitoring and mitigation services for the ISO and the employees of the External Market Monitor that perform market monitoring and mitigation services for the ISO shall also comply with the following additional ethical conduct standards. In the event of a conflict between one or more standards set forth below and one or more standards contained in the ISO New England Inc. Code of Conduct, the more stringent standard(s) shall control.

III.A.18.2.1. Prohibition on Employment with a Market Participant.
No such employee shall serve as an officer, director, employee or partner of a Market Participant.

III.A.18.2.2. Prohibition on Compensation for Services.

No such employee shall be compensated, other than by the ISO or, in the case of employees of the External Market Monitor, by the External Market Monitor, for any expert witness testimony or other commercial services, either to the ISO or to any other party, in connection with any legal or regulatory proceeding or commercial transaction relating to the ISO or the New England Markets.

III.A.18.2.3. Additional Standards Applicable to External Market Monitor.

In addition to the standards referenced in the remainder of this Section 18 of ***Appendix A***, the employees of the External Market Monitor that perform market monitoring and mitigation services for the ISO are subject to conduct standards set forth in the External Market Monitor Services Agreement entered into between the External Market Monitor and the ISO, as amended from time-to-time. In the event of a conflict between one or more standards set forth in the External Market Monitor Services Agreement and one or more standards set forth above or in the ISO New England Inc. Code of Conduct, the more stringent standard(s) shall control.

III.A.19. Protocols on Referral to the Commission of Suspected Violations.

(A) The Internal Market Monitor or External Market Monitor is to make a non-public referral to the Commission in all instances where the Internal Market Monitor or External Market Monitor has reason to believe that a Market Violation has occurred. While the Internal Market Monitor or External Market Monitor need not be able to prove that a Market Violation has occurred, the Internal Market Monitor or External Market Monitor is to provide sufficient credible information to warrant further investigation by the Commission. Once the Internal Market Monitor or External Market Monitor has obtained sufficient credible information to warrant referral to the Commission, the Internal Market Monitor or External Market Monitor is to immediately refer the matter to the Commission and desist from independent action related to the alleged Market Violation. This does not preclude the Internal Market Monitor or External Market Monitor from continuing to monitor for any repeated instances of the activity by the same or other entities, which would constitute new Market Violations. The Internal Market Monitor or External Market Monitor is to respond to requests from the Commission for any additional information in connection with the alleged Market Violation it has referred.

(B) All referrals to the Commission of alleged Market Violations are to be in writing, whether transmitted electronically, by fax, mail or courier. The Internal Market Monitor or External Market Monitor may alert the Commission orally in advance of the written referral.

(C) The referral is to be addressed to the Commission's Director of the Office of Enforcement, with a copy also directed to both the Director of the Office of Energy Market Regulation and the General Counsel.

(D) The referral is to include, but need not be limited to, the following information

(1) The name(s) of and, if possible, the contact information for, the entity(ies) that allegedly took the action(s) that constituted the alleged Market Violation(s);

(2) The date(s) or time period during which the alleged Market Violation(s) occurred and whether the alleged wrongful conduct is ongoing;

(3) The specific rule or regulation, and/or tariff provision, that was allegedly violated, or the nature of any inappropriate dispatch that may have occurred;

(4) The specific act(s) or conduct that allegedly constituted the Market Violation;

(5) The consequences to the market resulting from the acts or conduct, including, if known, an estimate of economic impact on the market;

(6) If the Internal Market Monitor or External Market Monitor believes that the act(s) or conduct constituted a violation of the anti-manipulation rule of Part 1c of the Commission's Rules and Regulations, 18 C.F.R. Part 1c, a description of the alleged manipulative effect on market prices, market conditions, or market rules;

(7) Any other information the Internal Market Monitor or External Market Monitor believes is relevant and may be helpful to the Commission.

(E) Following a referral to the Commission, the Internal Market Monitor or External Market Monitor is to continue to notify and inform the Commission of any information that the Internal Market Monitor or External Market Monitor learns of that may be related to the referral, but the Internal Market Monitor or External Market Monitor is not to undertake any investigative steps regarding the referral except at the express direction of the Commission or Commission staff.

III.A.20. Protocol on Referrals to the Commission of Perceived Market Design Flaws and Recommended Tariff Changes.

(A) The Internal Market Monitor or External Market Monitor is to make a referral to the Commission in all instances where the Internal Market Monitor or External Market Monitor has reason to believe market design flaws exist that it believes could effectively be remedied by rule or tariff changes. The Internal Market Monitor or External Market Monitor must limit distribution of its identifications and recommendations to the ISO and to the Commission in the event it believes broader dissemination could lead to exploitation, with an explanation of why further dissemination should be avoided at that time.

(B) All referrals to the Commission relating to perceived market design flaws and recommended tariff changes are to be in writing, whether transmitted electronically, by fax, mail, or courier. The Internal Market Monitor or External Market Monitor may alert the Commission orally in advance of the written referral.

(C) The referral should be addressed to the Commission's Director of the Office of Energy Market Regulation, with copies directed to both the Director of the Office of Enforcement and the General Counsel.

(D) The referral is to include, but need not be limited to, the following information.

(1) A detailed narrative describing the perceived market design flaw(s);

(2) The consequences of the perceived market design flaw(s), including, if known, an estimate of economic impact on the market;

(3) The rule or tariff change(s) that the Internal Market Monitor or External Market Monitor believes could remedy the perceived market design flaw;

(4) Any other information the Internal Market Monitor or External Market Monitor believes is relevant and may be helpful to the Commission.

(E) Following a referral to the Commission, the Internal Market Monitor or External Market Monitor is to continue to notify and inform the Commission of any additional information regarding the perceived market design flaw, its effects on the market, any additional or modified observations concerning the rule or tariff changes that could remedy the perceived design flaw, any recommendations made by the Internal Market Monitor or External Market Monitor to the regional transmission organization or independent system operator, stakeholders, market participants or state commissions regarding the perceived design flaw, and any actions taken by the regional transmission organization or independent system operator regarding the perceived design flaw.

III.A.21. Review of Offers From New Resources in the Forward Capacity Market.

The Internal Market Monitor shall review offers from new resources in the Forward Capacity Auction as described in this Section III.A.21.

III.A.21.1. Offer Review Trigger Prices.

For each new technology type, the Internal Market Monitor shall establish an Offer Review Trigger Price. Offers in the Forward Capacity Auction at prices that are equal to or above the relevant Offer Review Trigger Price will not be subject to further review by the Internal Market Monitor. A request to submit offers in the Forward Capacity Auction at prices that are below the relevant Offer Review Trigger Price must be submitted in advance of the Forward Capacity Auction as described in Sections III.13.1.1.2.2.3,

III.13.1.3.5 or III.13.1.4.1.1.2.8 and shall be reviewed by the Internal Market Monitor as described in this Section III.A.21.

III.A.21.1.1. Offer Review Trigger Prices for the Forward Capacity Auction.

For resources other than New Import Capacity Resources, the Offer Review Trigger Prices for the twelfth Forward Capacity Auction (for the Capacity Commitment Period beginning on June 1, 2021) shall be as follows:

Generating Capacity Resources	
Technology Type	**Offer Review Trigger Price ($/kW-month)**
combustion turbine	$6.503
combined cycle gas turbine	$7.856
on-shore wind	$11.025

Demand Capacity Resources - Commercial and Industrial	
Technology Type	**Offer Review Trigger Price ($/kW-month)**
Load Management and/or previously installed Distributed Generation	$1.008
new Distributed Generation	based on generation technology type
Energy Efficiency	$0.000

Demand Capacity Resources – Residential	
Technology Type	**Offer Review Trigger Price ($/kW-month)**
Load Management	$7.559
previously installed Distributed Generation	$1.008
new Distributed Generation	based on generation technology type
Energy Efficiency	$0.000

Other Resources	
All other technology types	Forward Capacity Auction Starting Price

Where a new resource is composed of assets having different technology types, the resource's Offer Review Trigger Price will be calculated in accordance with the weighted average formula in Section III.A.21.2(c).

For purposes of determining the Offer Review Trigger Price of a Demand Capacity Resource composed in whole or in part of Distributed Generation, the Distributed Generation is considered new, rather than previously installed, if (1) the Project Sponsor for the New Demand Capacity Resource has participated materially in the development, installation or funding of the Distributed Generation during the five years prior to commencement of the Capacity Commitment Period for which the resource is being qualified for participation, and (2) the Distributed Generation has not been assigned to a Demand Capacity Resource with a Capacity Supply Obligation in a prior Capacity Commitment Period.

For a New Import Capacity Resource that is backed by a single new External Resource and that is associated with an investment in transmission that increases New England's import capability, the Offer Review Trigger Prices in the table above shall apply, based on the technology type of the External Resource; provided that, if a New Import Capacity Resource is associated with an Elective Transmission Upgrade, it shall have an Offer Review Trigger Price of the Forward Capacity Auction Starting Price plus $0.01/kW-month.

For any other New Import Capacity Resource, the Offer Review Trigger Price shall be the Forward Capacity Auction Starting Price plus $0.01/kW-month.

III.A.21.1.2. Calculation of Offer Review Trigger Prices.

(a) The Offer Review Trigger Price for each of the technology types listed above shall be recalculated using updated data for the Capacity Commitment Period beginning on June 1, 2025 and no less often than once every three years thereafter. Where any Offer Review Trigger Price is recalculated, the Internal Market Monitor will review the results of the recalculation with stakeholders and the new Offer Review Trigger Price shall be filed with the Commission prior to the Forward Capacity Auction in which the Offer Review Trigger Price is to apply.

(b) For New Generating Capacity Resources, the methodology used to recalculate the Offer Review Trigger Price pursuant to subsection (a) above is as follows. Capital costs, expected non-capacity revenues and operating costs, assumptions regarding depreciation, taxes and discount rate are input into a capital budgeting model which is used to calculate the break-even contribution required from the Forward

Capacity Market to yield a discounted cash flow with a net present value of zero for the project. The Offer Review Trigger Price is set equal to the year-one capacity price output from the model. The model looks at 20 years of real-dollar cash flows discounted at a rate (Weighted Average Cost of Capital) consistent with that expected of a project whose output is under contract (i.e., a contract negotiated at arm's length between two unrelated parties).

(c) For New Demand Capacity Resources comprised of Energy Efficiency, the methodology used to recalculate the Offer Review Trigger Price pursuant to subsection (a) above shall be the same as that used for New Generating Capacity Resources, with the following exceptions. First, the model takes account of all costs incurred by the utility and end-use customer to deploy the efficiency measure. Second, rather than energy revenues, the model recognizes end-use customer savings associated with the efficiency programs. Third, the model assumes that all costs are expensed as incurred. Fourth, the benefits realized by end-use customers are assumed to have no tax implications for the utility. Fifth, the model discounts cash flows over the Measure Life of the energy efficiency measure.

(d) For New Demand Capacity Resources other than Demand Capacity Resources comprised of Energy Efficiency, the methodology used to recalculate the Offer Review Trigger Price pursuant to subsection (a) above is the same as that used for New Generating Capacity Resources, except that the model discounts cash flows over the contract life. For Demand Capacity Resources (other than those comprised of Energy Efficiency) that are composed primarily of large commercial or industrial customers that use pre-existing equipment or strategies, incremental costs include new equipment costs and annual operating costs such as customer incentives and sales representative commissions. For Demand Capacity Resources (other than Demand Capacity Resources comprised of Energy Efficiency) primarily composed of residential or small commercial customers that do not use pre-existing equipment or strategies, incremental costs include equipment costs, customer incentives, marketing, sales, and recruitment costs, operations and maintenance costs, and software and network infrastructure costs.

(e) For years in which no full recalculation is performed pursuant to subsection (a) above, the Offer Review Trigger Prices will be adjusted as follows:

(1) Each line item associated with capital costs that is included in the capital budgeting model will be associated with the indices included in the table below:

Cost Component	**Index**
gas turbines	BLS-PPI "Turbines and Turbine Generator Sets"

steam turbines	BLS-PPI "Turbines and Turbine Generator Sets"
wind turbines	Bloomberg Wind Turbine Price Index
Other Equipment	BLS-PPI "General Purpose Machinery and Equipment"
construction labor	BLS "Quarterly Census of Employment and Wages" 2371 Utility System Construction Average Annual Pay: – Combustion turbine and combined cycle gas turbine costs to be indexed to values corresponding to the location of Hampden County, Massachusetts – On-shore wind costs to be indexed to values corresponding to the location of Cumberland County, Maine
other labor	BLS "Quarterly Census of Employment and Wages" 2211 Power Generation and Supply Average Annual Pay: – Combustion turbine and combined cycle gas turbine costs to be indexed to values corresponding to the location of Hampden County, Massachusetts – On-shore wind costs to be indexed to values corresponding to the location of Cumberland County, Maine
materials	BLS-PPI "Materials and Components for Construction"
electric interconnection	BLS - PPI "Electric Power Transmission, Control, and Distribution"
gas interconnection	BLS - PPI "Natural Gas Distribution: Delivered to ultimate consumers for the account of others (transportation only)"
fuel inventories	Federal Reserve Bank of St. Louis "Gross Domestic Product: Implicit Price Deflator (GDPDEF)"

(2) Each line item associated with fixed operating and maintenance costs that is included in the capital budgeting model will be associated with the indices included in the table below:

Cost Component	**Index**
labor, administrative and general	BLS "Quarterly Census of Employment and Wages" 2211 Power Generation and Supply Average Annual Pay: – Combustion turbine and combined cycle gas turbine costs to be indexed to values corresponding to the location of Hampden County, Massachusetts – On-shore wind costs to be indexed to values corresponding to the location of Cumberland County, Maine
materials and contract services	BLS-PPI "Materials and Components for Construction"
site leasing costs	Federal Reserve Bank of St. Louis "Gross Domestic Product: Implicit Price Deflator (GDPDEF)"

(3) For each line item in (1) and (2) above, the ISO shall calculate a multiplier that is equal to the average of values published during the most recent 12 month period available at the time of making the adjustment divided by the average of the most recent 12 month period available at the time of establishing the Offer Review Trigger Prices for the FCA reflected in the table in Section III.A.21.1.1 above. The value of each line item associated with capital costs and fixed operating and maintenance costs included

in the capital budgeting model for the FCA reflected in the table in Section A.21.1.1 above will be adjusted by the relevant multiplier.

(4) The energy and ancillary services offset values for each technology type in the capital budgeting model shall be adjusted by inputting to the capital budgeting model the most recent Henry Hub natural gas futures prices, the Algonquin Citygates Basis natural gas futures prices and the Massachusetts Hub On-Peak electricity prices for the months in the Capacity Commitment Period beginning June 1, 2021, as published by ICE.

(5) Renewable energy credit values in the capital budgeting model shall be updated based on the most recent MA Class 1 REC price for the vintage closest to the first year of the Capacity Commitment Period associated with the relevant FCA as published by SNL Financial.

(6) The capital budgeting model and the Offer Review Trigger Prices adjusted pursuant to this subsection (e) will be published on the ISO's web site.

(7) If any of the values required for the calculations described in this subsection (e) are unavailable, then comparable values, prices or sources shall be used.

III.A.21.2. New Resource Offer Floor Prices and Offer Prices.

For every new resource participating in a Forward Capacity Auction, the Internal Market Monitor shall determine a New Resource Offer Floor Price or offer prices, as described in this Section III.A.21.2.

(a) For a Lead Market Participant with a New Capacity Resource that does not submit a request to submit offers in the Forward Capacity Auction at prices that are below the relevant Offer Review Trigger Price as described in Sections III.13.1.1.2.2.3, III.13.1.3.5 or III.13.1.4.1.1.2.8, the New Resource Offer Floor Price shall be calculated as follows:

> For a New Import Capacity Resource (other than a New Import Capacity Resource that is (i) backed by a single new External Resource and that is associated with an investment in transmission that increases New England's import capability or (ii) associated with an Elective Transmission Upgrade) the New Resource Offer Floor Price shall be $0.00/kW-month.

For a New Generating Capacity Resource, New Import Capacity Resource that is backed by a single new External Resource and that is associated with an investment in transmission that increases New England's import capability, New Import Capacity Resource that is associated with an Elective Transmission Upgrade, and New Demand Capacity Resource, the New Resource Offer Floor Price shall be equal to the applicable Offer Review Trigger Price.

A resource having a New Resource Offer Floor Price higher than the Forward Capacity Auction Starting Price shall not be included in the Forward Capacity Auction.

(b) For a Lead Market Participant with a New Capacity Resource that does submit a request to submit offers in the Forward Capacity Auction at prices that are below the relevant Offer Review Trigger Price as described in Sections III.13.1.1.2.2.3, III.13.1.3.5 and III.13.1.4.1.1.2.8, the resource's New Resource Offer Floor Price and offer prices in the case of a New Import Capacity Resource (other than a New Import Capacity Resource that is backed by a single new External Resource and that is associated with an investment in transmission that increases New England's import capability or a New Import Capacity Resource that is associated with an Elective Transmission Upgrade) shall be calculated as follows:

For a New Import Capacity Resource that is subject to the pivotal supplier test in Section III.A.23 and is found not to be associated with a pivotal supplier as determined pursuant to Section III.A.23, the resource's New Resource Offer Floor Price and offer prices shall be equal to the lower of (i) the requested offer price submitted to the ISO as described in Sections III.13.1.1.2.2.3 and III.13.1.3.5; or (ii) the price revised pursuant to Section III.13.1.3.5.7.

For any other New Capacity Resource, the Internal Market Monitor shall enter all relevant resource costs and non-capacity revenue data, as well as assumptions regarding depreciation, taxes, and discount rate into the capital budgeting model used to develop the relevant Offer Review Trigger Price and shall calculate the break-even contribution required from the Forward Capacity Market to yield a discounted cash flow with a net present value of zero for the project. The Internal Market Monitor shall compare the requested offer price to this capacity price estimate and the resource's New Resource Offer Floor Price and offer prices shall be determined as follows:

(i) The Internal Market Monitor will exclude any out-of-market revenue sources from the cash flows used to evaluate the requested offer price. Out-of-market revenues are any revenues that are: (a) not tradable throughout the New England Control Area or that are restricted to resources

within a particular state or other geographic sub-region; or (b) not available to all resources of the same physical type within the New England Control Area, regardless of the resource owner. Expected revenues associated with economic development incentives that are offered broadly by state or local government and that are not expressly intended to reduce prices in the Forward Capacity Market are not considered out-of-market revenues for this purpose. In submitting its requested offer price, the Project Sponsor shall indicate whether and which project cash flows are supported by a regulated rate, charge, or other regulated cost recovery mechanism. If the project is supported by a regulated rate, charge, or other regulated cost recovery mechanism, then that rate will be replaced with the Internal Market Monitor estimate of energy revenues. Where possible, the Internal Market Monitor will use like-unit historical production, revenue, and fuel cost data. Where such information is not available (e.g., there is no resource of that type in service), the Internal Market Monitor will use a forecast provided by a credible third party source. The Internal Market Monitor will review capital costs, discount rates, depreciation and tax treatment to ensure that it is consistent with overall market conditions. Any assumptions that are clearly inconsistent with prevailing market conditions will be adjusted.

(ii) For a New Demand Capacity Resource, the resource’s costs shall include all expenses, including incentive payments, equipment costs, marketing and selling and administrative and general costs incurred to acquire and/or develop the Demand Capacity Resource. Revenues shall include all non-capacity payments expected from the ISO-administered markets made for services delivered from the associated Demand Response Resource, and expected costs avoided by the associated end-use customer as a direct result of the installation or implementation of the associated Asset(s).

(iii) For a New Capacity Resource that has achieved commercial operation prior to the New Capacity Qualification Deadline for the Forward Capacity Auction in which it seeks to participate, the relevant capital costs to be entered into the capital budgeting model will be the undepreciated original capital costs adjusted for inflation. For any such resource, the prevailing market conditions will be those that were in place at the time of the decision to construct the resource.

(iv) Sufficient documentation and information must be included in the resource’s qualification package to allow the Internal Market Monitor to make the determinations described in this subsection (b). Such documentation should include all relevant financial estimates and cost

projections for the project, including the project's pro-forma financing support data. For a New Import Capacity Resource, such documentation should also include the expected costs of purchasing power outside the New England Control Area (including transaction costs and supported by forward power price index values or a power price forecast for the applicable Capacity Commitment Period), expected transmission costs outside the New England Control Area, and expected transmission costs associated with importing to the New England Control Area, and may also include reasonable opportunity costs and risk adjustments. For a new capacity resource that has achieved commercial operation prior to the New Capacity Qualification Deadline, such documentation should also include all relevant financial data of actual incurred capital costs, actual operating costs, and actual revenues since the date of commercial operation. If the supporting documentation and information required by this subsection (b) is deficient, the Internal Market Monitor, at its sole discretion, may consult with the Project Sponsor to gather further information as necessary to complete its analysis. If after consultation, the Project Sponsor does not provide sufficient documentation and information for the Internal Market Monitor to complete its analysis, then the resource's New Resource Offer Floor Price shall be equal to the Offer Review Trigger Price.

(v) If the Internal Market Monitor determines that the requested offer prices are consistent with the Internal Market Monitor's capacity price estimate, then the resource's New Resource Offer Floor Price shall be equal to the requested offer price, subject to the provisions of subsection (vii) concerning New Import Capacity Resources.

(vi) If the Internal Market Monitor determines that the requested offer prices are not consistent with the Internal Market Monitor's capacity price estimate, then the resource's offer prices shall be set to a level that is consistent with the capacity price estimate, as determined by the Internal Market Monitor. Any such determination will be explained in the resource's qualification determination notification and will be filed with the Commission as part of the filing described in Section III.13.8.1(c), subject to the provisions of subsection (vii) concerning New Import Capacity Resources.

(vii) For New Import Capacity Resources that have been found to be associated with a pivotal supplier as determined pursuant to Section III.A.23, if the supplier elects to revise the requested offer prices pursuant to Section III.13.1.3.5.7 to values that are below the Internal Market

Monitor's capacity price estimate established pursuant to subsection (v) or (vi), then the resource's offer prices shall be equal to the revised offer prices.

(c) For a new capacity resource composed of assets having different technology types the Offer Review Trigger Price shall be the weighted average of the Offer Review Trigger Prices of the asset technology types of the assets that comprise the resource, based on the expected capacity contribution from each asset technology type. Sufficient documentation must be included in the resource's qualification package to permit the Internal Market Monitor to determine the weighted average Offer Review Trigger Price.

III.A.22. [Reserved.]

III.A.23. Pivotal Supplier Test for Existing Capacity Resources and New Import Capacity Resources in the Forward Capacity Market.

III.A.23.1. Pivotal Supplier Test.

The pivotal supplier test is performed prior to the commencement of the Forward Capacity Auction at the system level and for each import-constrained Capacity Zone.

An Existing Capacity Resource or New Import Capacity Resource is associated with a pivotal supplier if, after removing all the supplier's FCA Qualified Capacity, the ability to meet the relevant requirement is less than the requirement. Only those New Import Capacity Resources that are not (i) backed by a single new External Resource and associated with an investment in transmission that increases New England's import capability, or (ii) associated with an Elective Transmission Upgrade, are subject to the pivotal supplier test.

For the system level determination, the relevant requirement is the Installed Capacity Requirement (net of HQICCs). For each import-constrained Capacity Zone, the relevant requirement is the Local Sourcing Requirement for that import-constrained Capacity Zone.

At the system level, the ability to meet the relevant requirement is the sum of the following:

(a) The total FCA Qualified Capacity from all Existing Generating Capacity Resources and Existing Demand Capacity Resources in the Rest-of-Pool Capacity Zone;

(b) For each modeled import-constrained Capacity Zone, the greater of:

(1) the total FCA Qualified Capacity from all Existing Generating Capacity Resources and Existing Demand Capacity Resources within the import-constrained Capacity Zone plus, for each modeled external interface connected to the import-constrained Capacity Zone, the lesser of: (i) the capacity transfer limit of the interface (net of tie benefits), and; (ii) the total amount of FCA Qualified Capacity from Import Capacity Resources over the interface, and;

(2) the Local Sourcing Requirement of the import-constrained Capacity Zone;

(c) For each modeled nested export-constrained Capacity Zone, the lesser of:

(1) the total FCA Qualified Capacity from all Existing Generating Capacity Resources and Existing Demand Capacity Resources within the nested export-constrained Capacity Zone plus, for each external interface connected to the nested export-constrained Capacity Zone, the lesser of: (i) the capacity transfer limit of the interface (net of tie benefits), and; (ii) the total amount of FCA Qualified Capacity from Import Capacity Resources over the interface, and;

(2) the Maximum Capacity Limit of the nested export-constrained Capacity Zone;

(d) For each modeled export-constrained Capacity Zone that is not a nested export-constrained Capacity Zone, the lesser of:

(1) the total FCA Qualified Capacity from all Existing Generating Capacity Resources and Existing Demand Capacity Resources within the export-constrained Capacity Zone, excluding the total FCA Qualified Capacity from Existing Generating Capacity Resources and Existing Demand Capacity Resources within a nested export-constrained Capacity Zone, plus, for each external interface connected to the export-constrained Capacity Zone that is not included in any nested export-constrained Capacity Zone, the lesser of: (i) the capacity transfer limit of the interface (net of tie benefits), and; (ii) the total amount of FCA Qualified Capacity from Import Capacity Resources over the interface, excluding the contribution from any nested export-constrained Capacity Zone as determined pursuant to Section III.A.23.1(c), and;

(2) the Maximum Capacity Limit of the export-constrained Capacity Zone minus the contribution from any associated nested export-constrained Capacity Zone as determined pursuant to Section III.A.23.1(c), and;

(e) For each modeled external interface connected to the Rest-of-Pool Capacity Zone, the lesser of:

(1) the capacity transfer limit of the interface (net of tie benefits), and;

(2) the total amount of FCA Qualified Capacity from Import Capacity Resources over the interface.

For each import-constrained Capacity Zone, the ability to meet the relevant requirement is the sum of the following:

(1) The total FCA Qualified Capacity from all Existing Generating Capacity Resources and Existing Demand Capacity Resources located within the import-constrained Capacity Zone; and
(2) For each modeled external interface connected to the import-constrained Capacity Zone, the lesser of: (1) the capacity transfer limit of the interface (net of tie benefits), and; (2) the total amount of FCA Qualified Capacity from Import Capacity Resources over the interface.

III.A.23.2. Conditions Under Which Capacity is Treated as Non-Pivotal.

FCA Qualified Capacity of a supplier that is determined to be pivotal under Section III.A.23.1 is treated as non-pivotal under the following four conditions:

(a) If the removal of a supplier's FCA Qualified Capacity in an export-constrained Capacity Zone or nested export-constrained Capacity Zone does not change the quantity calculated in Section III.A.23.1(c) for that export-constrained Capacity Zone or nested export-constrained Capacity Zone, then that capacity is treated as capacity of a non-pivotal supplier.
(b) If the removal of a supplier's FCA Qualified Capacity in the form of Import Capacity Resources at an external interface does not change the quantity calculated in Section III.A.23.1(d) for that interface, then that capacity is treated as capacity of a non-pivotal supplier.
(c) If the removal of a supplier's FCA Qualified Capacity in the form of Import Capacity Resources at an external interface connected to an import-constrained Capacity Zone does not change the quantity calculated in Section III.A.23.1(f) for that interface, then that capacity is treated as capacity of a non-pivotal supplier.
(d) If a supplier whose only FCA Qualified Capacity is a single capacity resource with a bid that (i) is not subject to rationing under Section III.13.1.2.3.1 or III.13.2.6, and (ii) contains only one price-quantity pair for the entire FCA Qualified Capacity amount, then the capacity of that resource is treated as capacity of a non-pivotal supplier.

III.A.23.3. Pivotal Supplier Test Notification of Results.

Results of the pivotal supplier test will be made available to suppliers no later than seven days prior to the start of the Forward Capacity Auction.

III.A.23.4. Qualified Capacity for Purposes of Pivotal Supplier Test.

For purposes of the tests performed in Sections III.A.23.1 and III.A.23.2, the FCA Qualified Capacity of a supplier includes the capacity of Existing Generating Capacity Resources, Existing Demand Capacity Resources, Existing Import Capacity Resources, and New Import Capacity Resources (other than (i) a New Import Capacity Resource that is backed by a single new External Resource and that is associated with an investment in transmission that increases New England's import capability; and (ii) a New Import Capacity Resource associated with an Elective Transmission Upgrade) that is controlled by the supplier or its Affiliates.

For purposes of determining the ability to meet the relevant requirement under Section III.A.23.1, the FCA Qualified Capacity from New Import Capacity Resources does not include (i) any New Import Capacity Resource that is backed by a single new External Resource and that is associated with an investment in transmission that increases New England's import capability; and (ii) any New Import Capacity Resource associated with an Elective Transmission Upgrade.

For purposes of determining the FCA Qualified Capacity of a supplier or its Affiliates under Section III.A.23.4, "control" or "controlled" means the possession, directly or indirectly, of the authority to direct the decision-making regarding how capacity is offered into the Forward Capacity Market, and includes control by contract with unaffiliated third parties. In complying with Section I.3.5 of the ISO Tariff, a supplier shall inform the ISO of all capacity that it and its Affiliates control under this Section III.A.23.4 and all capacity the control of which it has contracted to a third party.

III.A.24. Retirement Portfolio Test for Existing Capacity Resources in the Forward Capacity Market.

The retirement portfolio test is performed prior to the commencement of the Forward Capacity Auction for each Lead Market Participant submitting a Permanent De-List Bid or Retirement De-List Bid. The test will be performed as follows:

If

i. The annual capacity revenue from the Lead Market Participant's total FCA Qualified Capacity, not including the FCA Qualified Capacity associated with the Permanent De-List Bid or Retirement De-List Bid, is greater than

ii. the annual capacity revenue from the Lead Market Participant's total FCA Qualified Capacity, including the FCA Qualified Capacity associated with the Permanent De-List Bid or Retirement De-List Bid, then

iii. the Lead Market Participant will be found to have a portfolio benefit pursuant to the retirement portfolio test.

Where,

iv. the Lead Market Participant's annual capacity revenue from the Lead Market Participant's total FCA Qualified Capacity not including the FCA Qualified Capacity associated with the Permanent De-List Bid or Retirement De-List Bid is calculated as the product of (a) the Lead Market Participant's total FCA Qualified Capacity not including the FCA Qualified Capacity associated with the Permanent De-List Bid or Retirement De-List Bid and (b) the Internal Market Monitor-estimated capacity clearing price not including the FCA Qualified Capacity associated with the Permanent De-List Bid or Retirement De-List Bid.

v. The Lead Market Participant's annual capacity revenue from the Lead Market Participant's total FCA Qualified Capacity including the FCA Qualified Capacity associated with the Permanent De-List Bid or Retirement De-List Bid is calculated as the product of (a) the Lead Market Participant's total FCA Qualified Capacity including the FCA Qualified Capacity associated with the Permanent De-List Bid or Retirement De-List Bid and (b) the Internal Market Monitor-estimated capacity clearing price including the FCA Qualified Capacity associated with the Permanent De-List Bid or Retirement De-List Bid.

vi. The Internal Market Monitor-estimated capacity clearing price, not to exceed the Forward Capacity Auction Starting Price, is based on the parameters of the System-Wide Capacity Demand Curve and Capacity Zone Demand Curves as specified in Section III.13.2.2.

For purposes of the test performed in this Section III.A.24, the FCA Qualified Capacity of a Lead Market Participant includes the capacity of Existing Capacity Resources that is controlled by the Lead Market Participant or its Affiliates.

For purposes of determining the FCA Qualified Capacity of a Lead Market Participant or its Affiliates under this Section III.A.24, “control” or “controlled” means the possession, directly or indirectly, of the authority to direct the decision-making regarding how capacity is offered into the Forward Capacity Market, and includes control by contract with unaffiliated third parties. In complying with Section I.3.5 of the ISO Tariff, a Lead Market Participant shall inform the ISO of all capacity that it and its Affiliates control under this Section III.A.4 and all capacity the control of which it has contracted to a third party.

APPENDIX K

INVENTORIED ENERGY PROGRAM

III.K Inventoried Energy Program

For the winter of 2023-2024 (the "relevant winter period"), the ISO shall administer an inventoried energy program in accordance with the provisions of this Appendix K.

III.K.1. Submission of Election Information

Participation in the inventoried energy program is voluntary. To participate in both the forward and spot components of the program, the information listed in this Section III.K.1 must be submitted to the ISO no later than the October 1 immediately preceding the start of the relevant winter and must reflect an ability to provide the submitted inventoried energy throughout the relevant winter period. To participate in the spot component of the program only, the information listed in this Section III.K.1 may be submitted to the ISO through the end of the relevant winter period, in which case participation will begin (prospectively only) upon review and approval by the ISO of the information submitted.

(a) A list of the Market Participant's assets that will participate in the inventoried energy program, with a description for each such asset of: the Market Participant's Ownership Share in the asset; the types of fuel it can use; the approximate maximum amount of each fuel type that can be stored on site (and in upstream ponds) or, in the case of natural gas, the amount that is subject to a contract meeting the requirements described in Section III.K.1(a)(iii), as measured pursuant to the provisions of Section III.K.3.2.1.1(a); and a list of other assets at the same facility that share the fuel inventory (or, in the case of natural gas, a list of assets at the same or any other facility that can also take fuel pursuant to the same contract).

(i) The following asset types may not be included in a Market Participant's list of assets: Settlement Only Resources; assets not located in the New England Control Area; assets being compensated pursuant to a cost-of-service agreement (as described in Section III.13.2.5.2.5) during the relevant winter period; and assets that cannot operate on stored fuel (or natural gas subject to a contract as described in Section III.K.1(a)(iii)) at the ISO's direction.

(ii) A Demand Response Resource with Distributed Generation may be included in a Market Participant's list of assets.

(iii) For any asset listed that will participate in the inventoried energy program using natural gas as a fuel type, the Market Participant must also submit an executed contract for firm delivery of natural gas. Any such contract must include no limitations on when natural gas can be called during a day, and must specify the parties to the contract, the volume of gas to be delivered, the price to be paid for that gas, the pipeline delivery point name and gas meter number of the listed asset, terms related to pipeline transportation to the meter of the listed asset (with indication of whether the gas supplier or another entity is providing the transportation), and all other terms, conditions, or related agreements affecting whether and when gas will be delivered, the volume of gas to be delivered, and the price to be paid for that gas.

(b) A detailed description of how the Market Participant's energy inventory will be measured after each Inventoried Energy Day in accordance with the provisions of Section III.K.3.2.1.1 and converted to MWh (including the rates at which fuel is converted to energy for each asset). Where assets share fuel inventory, if the Market Participant believes that fuel should be allocated among those assets in a manner other than the default approach described in Section III.K.3.2.1.1(e)(ii), this description should explain and support that alternate allocation.

(c) Whether the Market Participant is electing to participate in only the spot component of the inventoried energy program or in both the forward and spot components.

(d) If electing to participate in both the forward and spot components of the program, the total MWh value for which the Market Participant elects to be compensated at the forward rate (the "Forward Energy Inventory Election"). This MWh value must be less than or equal to the combined MW output that the assets listed by the Market Participant (adjusted to account for Ownership Share) could provide over a period of 72 hours, as limited by the maximum amount of each fuel type that can be stored on site (and in upstream ponds) for each asset and as limited by the terms of any natural gas contracts submitted pursuant to Section III.K.1(a)(iii). If the Market Participant is submitting one or more contracts for natural gas, the Market Participant must indicate whether any of the suppliers listed in those contracts have the capability to deliver vaporized liquefied natural gas to New England, and if so, what portion of its Forward Energy Inventory Election, in MWh, should be attributed to liquefied natural gas (the "Forward LNG Inventory Election"). (For Market Participants electing to participate in only the spot component of the program, the Forward Energy Inventory Election and Forward LNG Inventory Election shall be zero.)

III.K.1.1 ISO Review and Approval of Election Information

The ISO will review each Market Participant's election submission, and may confer with the Market Participant to clarify or supplement the information provided. The ISO shall modify the amounts as necessary to ensure consistency with asset-specific operational characteristics, terms and conditions associated with submitted contracts, regulatory restrictions, and the requirements of the inventoried energy program. For election information that is submitted no later than October 1, the ISO will report the final program participation values to the Market Participant by the November 1 immediately preceding the start of the relevant winter, and participation will begin on December 1. For election information that is submitted after October 1 (spot component participation only), the ISO will, as soon as practicable, report the final program participation values and the date that participation will begin to the Market Participant.

(a) In performing this review, the ISO shall reject all or any portions of a contract for natural gas that:

(i) does not meet the requirements of Section III.K.1(a)(iii); or

(ii) requires (except in the case of an asset that is supplied from a liquefied natural gas facility adjacent and directly connected to the asset) the Market Participant to incur incremental costs to exercise the contract that may be greater than 250 percent of the average of the sum of the monthly Henry Hub natural gas futures prices and the Algonquin Citygates Basis natural gas futures prices for the December, January, and February of the relevant winter period on the earlier of the day the contract is executed and the first Business Day in October prior to that winter period.

(b) In performing this review, if the total of the Forward LNG Inventory Elections from all participating Market Participants (excluding amounts to be supplied to an asset from a liquefied natural gas facility adjacent and directly connected to the asset) exceeds 560,000 MWh, the ISO shall prorate each such Forward LNG Inventory Election such that the sum of such Forward LNG Inventory Elections is no greater than 560,000 MWh, and each Market Participant's Forward Energy Inventory Election shall be adjusted accordingly.

III.K.1.2 Posting of Forward Energy Inventory Election Amount

As soon as practicable after the November 1 immediately preceding the start of the relevant winter, the ISO will post to its website the total amount of Forward Energy Inventory Elections and Forward LNG Inventory Elections participating in the inventoried energy program for that winter.

III.K.2 Inventoried Energy Base Payments

A Market Participant participating in the forward and spot components of the inventoried energy program shall receive a base payment for each day of the months of December, January, and February. Each such base payment shall be equal to the Market Participant's Forward Energy Inventory Election (adjusted as described in Section III.K.1.1) multiplied by $82.49 per MWh and divided by the total number of days in those three months.

III.K.3 Inventoried Energy Spot Payments

A Market Participant participating in the spot component of the inventoried energy program (whether or not the Market Participant is also participating in the forward component of the program) shall receive a spot payment for each Inventoried Energy Day as calculated pursuant to this Section III.K.3.

III.K.3.1 Definition of Inventoried Energy Day

An Inventoried Energy Day shall exist for any Operating Day that occurs in the months of December, January, or February and for which the average of the high temperature and the low temperature on that Operating Day, as measured and reported by the National Weather Service at Bradley International Airport in Windsor Locks, Connecticut, is less than or equal to 17 degrees Fahrenheit.

III.K.3.2 Calculation of Inventoried Energy Spot Payment

A Market Participant's spot payment for an Inventoried Energy Day, which may be positive or negative, shall equal the Market Participant's Real-Time Energy Inventory minus its Forward Energy Inventory Election, with the difference multiplied by $8.25 per MWh.

III.K.3.2.1 Calculation of Real-Time Energy Inventory

A Market Participant's Real-Time Energy Inventory for an Inventoried Energy Day shall be the sum of the Real-Time Energy Inventories for each of the Market Participant's assets participating in the program (adjusted as described in Section III.K.3.2.1.2); provided, however, that where more than one Market Participant has an Ownership Share in an asset, the asset's Real-Time Energy Inventory will be apportioned based on each Market Participant's Ownership Share.

III.K.3.2.1.1 Asset-Level Real-Time Energy Inventory

Each asset's Real-Time Energy Inventory will be determined as follows:

(a) The Market Participant must measure and report to the ISO the Real-Time Energy Inventory for each of the assets participating in the program between 7:00 a.m. and 8:00 a.m. on the Operating Day immediately following each Inventoried Energy Day. The Real-Time Energy Inventory must be reported to the ISO both in MWh and in units appropriate to the fuel type and measured in accordance with the following provisions:

(i) Oil. The Real-Time Energy Inventory of an asset that runs on oil shall be the number of dedicated barrels of oil stored in an in-service tank (located on site or at an adjacent location with direct pipeline transfer capability to the asset), excluding any amount that is unobtainable or unusable (due to priming requirements, sediment, volume below the suction line, or any other reason).

(ii) Coal. The Real-Time Energy Inventory of an asset that runs on coal shall be the number of metric tons of coal stored on site, excluding any amount that is unobtainable or unusable for any reason.

(iii) Nuclear. The Real-Time Energy Inventory of a nuclear asset shall be the number of days until the asset's next scheduled refueling outage.

(iv) Natural Gas. The Real-Time Energy Inventory for an asset that runs on natural gas shall be the amount of natural gas available to the asset pursuant to the terms of the relevant contracts submitted pursuant to Section III.K.1(a)(iii), adjusted to reflect any limitation that the suppliers listed in the contracts may have on the capability to deliver natural gas. The Market Participant must specify what portion of the asset's Real-Time Energy Inventory, in MWh, is associated with liquefied natural gas.

(v) Pumped Hydro. The Real-Time Energy Inventory of a pumped storage asset shall be the amount of water (in gallons or by elevation, consistent with the description provided by the Market Participant pursuant to Section III.K.1(b)) in the on-site reservoir that is available for generation, excluding any amount that is unobtainable or unusable for any reason.

(vi) Pondage. The Real-Time Energy Inventory of an asset with pondage shall be the amount of water (in gallons or by elevation, consistent with the description provided by the Market Participant pursuant to Section III.K.1(b)) in on-site and upstream ponds controlled by the Market Participant with a transit time to the asset of no more than 12 hours, excluding any amount that is unobtainable or unusable for any reason.

(vii) Biomass/Refuse. The Real-Time Energy Inventory of an asset that runs on biomass or refuse shall be the number of metric tons of the relevant material stored on site, excluding any amount that is unobtainable or unusable for any reason.

(viii) Electric Storage Facility. The Real-Time Energy Inventory of an Electric Storage Facility shall be its available energy in MWh.

(b) If the Market Participant fails to measure or report the energy inventory or fuel amounts for an asset as required, that asset's Real-Time Energy Inventory for the Inventoried Energy Day shall be zero.

(c) The Market Participant must limit each asset's Real-Time Energy Inventory as appropriate to respect federal and state restrictions on the use of the fuel (such as water flow or emissions limitations).

(d) The reported amounts are subject to verification by the ISO. As part of any such verification, the ISO may request additional information or documentation from a Market Participant, or may require a certificate signed by a Senior Officer of the Market Participant attesting that the reported amount of fuel is available to the Market Participant as required by the provisions of the inventoried energy program.

(e) In determining final Real-Time Energy Inventory amounts for each asset, the ISO will:

(i) adjust the reported amounts consistent with the results of any verification performed pursuant to Section III.K.3.2.1.1(d);

(ii) allocate shared fuel inventory among the relevant assets in a manner that maximizes its use based on the efficiency with which the assets convert fuel to energy (unless

information submitted pursuant to Section III.K.1(b) supports a different allocation) and that is consistent with any applicable contract provisions (in the case of natural gas) and maximum daily production limits of the assets sharing fuel inventory; and

(iii) limit each asset's Real-Time Energy Inventory to the asset's average available outage-adjusted output on the Inventoried Energy Day for a maximum duration of 72 hours.

III.K.3.2.1.2 Proration of Liquefied Natural Gas

If the total amount of Real-Time Energy Inventory associated with liquefied natural gas (excluding amounts to be supplied to an asset from a liquefied natural gas facility adjacent and directly connected to the asset) exceeds 560,000 MWh, then the ISO shall prorate such Real-Time Energy Inventory associated with liquefied natural gas as follows:

(a) any Real-Time Energy Inventory associated with liquefied natural gas that corresponds to a Market Participant's Forward LNG Inventory Election (prorated as described in Section III.K.1.1(b)) shall be counted without reduction; and

(b) any Real-Time Energy Inventory associated with liquefied natural gas that does not correspond to a Market Participant's Forward LNG Inventory Election (prorated as described in Section III.K.1.1(b)) shall be prorated such that the sum of the Real-Time Energy Inventory associated with liquefied natural gas (including the amount described in Section III.K.3.2.1.2(a)) does not exceed 560,000 MWh.

III.K.4 Cost Allocation

Costs associated with the inventoried energy program shall be allocated on a regional basis to Real-Time Load Obligation, excluding Real-Time Load Obligation associated with Storage DARDs and Real-Time Load Obligation associated with Coordinated External Transactions. Costs associated with base payments shall be allocated across all days of the months of December, January, and February; costs associated with spot payments shall be allocated to the relevant Inventoried Energy Day.

SECTION III

MARKET RULE 1

APPENDIX L

ISO NEW ENGLAND FUEL SECURITY RELIABILITY REVIEW STANDARD

As described in Section III.13.2.5.2.5A, a fuel security reliability review will be performed for certain submissions by Existing Generating Capacity Resources. This Appendix establishes the reliability trigger for that fuel security reliability review. This Appendix L will remain in effect for the 2022/23 and 2023/24 Capacity Commitment Periods, after which this Appendix L will sunset.

The fuel security model used for reliability reviews shall consist of an hour-by-hour chronological simulation of the electric supply for the winter period from the beginning of December through the end of February. As applied to the fuel security reliability review model established pursuant to Appendix I of Planning Procedure No. 10, observation of either of the following will result in the generator being tested having its (i) Retirement De-List Bids, (ii) substitution auction demand bids, and (iii) certain bilateral transactions and reconfiguration auction demand bid offers rejected for reliability reasons:

(i) The retirement will result in the depletion of 10-minute reserves below 700 MW in any hour in the absence of a contingency in more than one liquefied natural gas supply scenario case or,

(ii) the use of load shedding in any hour pursuant to Operating Procedure No. 7.

Attachment E-1

NEPOOL Marked Tariff

I.2 Rules of Construction; Definitions

I.2.1. Rules of Construction:

In this Tariff, unless otherwise provided herein:

(a) words denoting the singular include the plural and vice versa;

(b) words denoting a gender include all genders;

(c) references to a particular part, clause, section, paragraph, article, exhibit, schedule, appendix or other attachment shall be a reference to a part, clause, section, paragraph, or article of, or an exhibit, schedule, appendix or other attachment to, this Tariff;

(d) the exhibits, schedules and appendices attached hereto are incorporated herein by reference and shall be construed with an as an integral part of this Tariff to the same extent as if they were set forth verbatim herein;

(e) a reference to any statute, regulation, proclamation, ordinance or law includes all statutes, regulations, proclamations, amendments, ordinances or laws varying, consolidating or replacing the same from time to time, and a reference to a statute includes all regulations, policies, protocols, codes, proclamations and ordinances issued or otherwise applicable under that statute unless, in any such case, otherwise expressly provided in any such statute or in this Tariff;

(f) a reference to a particular section, paragraph or other part of a particular statute shall be deemed to be a reference to any other section, paragraph or other part substituted therefor from time to time;

(g) a definition of or reference to any document, instrument or agreement includes any amendment or supplement to, or restatement, replacement, modification or novation of, any such document, instrument or agreement unless otherwise specified in such definition or in the context in which such reference is used;

(h) a reference to any person (as hereinafter defined) includes such person's successors and permitted assigns in that designated capacity;

(i) any reference to "days" shall mean calendar days unless "Business Days" (as hereinafter defined) are expressly specified;

(j) if the date as of which any right, option or election is exercisable, or the date upon which any amount is due and payable, is stated to be on a date or day that is not a Business Day, such right, option or election may be exercised, and such amount shall be deemed due and payable, on the next succeeding Business Day with the same effect as if the same was exercised or made on such date or day (without, in the case of any such payment, the payment or accrual of any interest or

other late payment or charge, provided such payment is made on such next succeeding Business Day);

(k) words such as "hereunder," "hereto," "hereof" and "herein" and other words of similar import shall, unless the context requires otherwise, refer to this Tariff as a whole and not to any particular article, section, subsection, paragraph or clause hereof; and a reference to "include" or "including" means including without limiting the generality of any description preceding such term, and for purposes hereof the rule of *ejusdem generis* shall not be applicable to limit a general statement, followed by or referable to an enumeration of specific matters, to matters similar to those specifically mentioned.

I.2.2. Definitions:

In this Tariff, the terms listed in this section shall be defined as described below:

Active Demand Capacity Resource is one or more Demand Response Resources located within the same Dispatch Zone, that is registered with the ISO, assigned a unique resource identification number by the ISO, and participates in the Forward Capacity Market to fulfill a Market Participant's Capacity Supply Obligation pursuant to Section III.13 of Market Rule 1.

Actual Capacity Provided is the measure of capacity provided during a Capacity Scarcity Condition, as described in Section III.13.7.2.2 of Market Rule 1.

Actual Load is the consumption at the Retail Delivery Point for the hour.

Additional Resource Blackstart O&M Payment is defined and calculated as specified in Section 5.1.2 of Schedule 16 to the OATT.

Additional Resource Specified-Term Blackstart Capital Payment is defined and calculated as specified in Section 5.1.2 of Schedule 16 to the OATT.

Additional Resource Standard Blackstart Capital Payment is defined and calculated as specified in Section 5.1.2 of Schedule 16 to the OATT.

Administrative Costs are those costs incurred in connection with the review of Applications for transmission service and the carrying out of System Impact Studies and Facilities Studies.

Administrative Export De-List Bid is a bid that may be submitted in a Forward Capacity Auction by certain Existing Generating Capacity Resources subject to a multi-year contract to sell capacity outside of the New England Control Area during the associated Capacity Commitment Period, as described in Section III.13.1.2.3.1.4 of Market Rule 1.

Administrative Sanctions are defined in Section III.B.4.1.2 of Appendix B of Market Rule 1.

ADR Neutrals are one or more firms or individuals identified by the ISO with the advice and consent of the Participants Committee that are prepared to act as neutrals in ADR proceedings under Appendix D to Market Rule 1.

Advance is defined in Section IV.A.3.2 of the Tariff.

Affected Party, for purposes of the ISO New England Billing Policy, is defined in Section 6.3.5 of the ISO New England Billing Policy.

Affiliate is any person or entity that controls, is controlled by, or is under common control by another person or entity. For purposes of this definition, "control" means the possession, directly or indirectly, of the authority to direct the management or policies of an entity. A voting interest of ten percent or more shall create a rebuttable presumption of control.

AGC is automatic generation control.

AGC SetPoint is the desired output signal for a Resource providing Regulation that is produced by the AGC system as frequently as every four seconds.

AGC SetPoint Deadband is a deadband expressed in megawatts that is applied to changing values of the AGC SetPoint for generating units.

Allocated Assessment is a Covered Entity’s right to seek and obtain payment and recovery of its share in any shortfall payments under Section 3.3 or Section 3.4 of the ISO New England Billing Policy.

Alternative Dispute Resolution (ADR) is the procedure set forth in Appendix D to Market Rule 1.

Alternative Technology Regulation Resource (ATRR) is one or more facilities capable of providing Regulation that have been registered in accordance with the Asset Registration Process. An Alternative Technology Regulation Resource is eligible to participate in the Regulation Market.

Ancillary Services are those services that are necessary to support the transmission of electric capacity and energy from resources to loads while maintaining reliable operation of the New England Transmission System in accordance with Good Utility Practice.

Announced Schedule 1 EA Amount, Announced Schedule 2 EA Amount, Announced Schedule 3 EA Amount are defined in Section IV.B.2.2 of the Tariff.

Annual Transmission Revenue Requirements are the annual revenue requirements of a PTO's PTF or of all PTOs' PTF for purposes of the OATT shall be the amount determined in accordance with Attachment F to the OATT.

Annual Reconfiguration Transaction is a bilateral transaction that may be used in accordance with Section III.13.5.4 of Market Rule 1 to specify a price when a Capacity Supply Obligation is transferred using supply offers and demand bids in Annual Reconfiguration Auctions.

Applicants, for the purposes of the ISO New England Financial Assurance Policy, are entities applying for Market Participant status or for transmission service from the ISO.

Application is a written request by an Eligible Customer for transmission service pursuant to the provisions of the OATT.

Asset is a Generator Asset, a Demand Response Asset, a component of an On-Peak Demand Resource or Seasonal Peak Demand Resource, a Load Asset (including an Asset Related Demand), an Alternative Technology Regulation Resource, or a Tie-Line Asset.

Asset Registration Process is the ISO business process for registering an Asset.

Asset Related Demand is a Load Asset that has been discretely modeled within the ISO's dispatch and settlement systems, settles at a Node, has been registered in accordance with the Asset Registration

Process, and is made up of either: (1) one or more individual end-use metered customers receiving service from the same point or points of electrical supply with an aggregate average hourly load of 1 MW or greater during the 12 months preceding its registration; (2) a Storage DARD with a consumption capability of at least 0.1 MW; or (3) one or more storage facilities that are not Electric Storage Facilities with an aggregate consumption capability of at least 1 MW.

Asset Related Demand Bid Block-Hours are Block-Hours assigned to the Lead Market Participant for each Asset Related Demand bid. Blocks of the bid in effect for each hour will be totaled to determine the daily quantity of Asset Related Demand Bid Block-Hours. In the case that a Resource has a Real-Time unit status of "unavailable" for an entire day, that day will not contribute to the quantity of Asset Related Demand Bid Block-Hours. However, if the Resource has at least one hour of the day with a unit status of "available," the entire day will contribute to the quantity of Asset Related Demand Bid Block-Hours.

Asset-Specific Going Forward Costs are the net costs of an asset that is part of an Existing Generating Capacity Resource, calculated for the asset in the same manner as the net costs of Existing Generating Capacity Resources as described in Section III.13.1.2.3.2.1.1.1 (for an asset with a Static De-List Bid or an Export Bid) or Section III.13.1.2.3.2.1.1.2 (for an asset with a Permanent De-List Bid or Retirement De-List Bid).

Assigned Meter Reader reports to the ISO the hourly and monthly MWh associated with the Asset. These MWh are used for settlement. The Assigned Meter Reader may designate an agent to help fulfill its Assigned Meter Reader responsibilities; however, the Assigned Meter Reader remains functionally responsible to the ISO.

Auction Revenue Right (ARR) is a right to receive FTR Auction Revenues in accordance with Appendix C of Market Rule 1.

Auction Revenue Right Allocation (ARR Allocation) is defined in Section 1 of Appendix C of Market Rule 1.

Auction Revenue Right Holder (ARR Holder) is an entity which is the record holder of an Auction Revenue Right (excluding an Incremental ARR) in the register maintained by the ISO.

Authorized Commission is defined in Section 3.3 of the ISO New England Information Policy.

Authorized Person is defined in Section 3.3 of the ISO New England Information Policy.

Automatic Response Rate is the response rate, in MW/Minute, at which a Market Participant is willing to have a Regulation Resource change its output or consumption while providing Regulation between the Regulation High Limit and Regulation Low Limit.

Available Energy is a value that reflects the MWhs of energy available from an Electric Storage Facility for economic dispatch.

Available Storage is a value that reflects the MWhs of unused storage available from an Electric Storage Facility for economic dispatch of consumption.

Average Hourly Load Reduction is either: (i) the sum of the On-Peak Demand Resource's electrical energy reduction during Demand Resource On-Peak Hours in the month divided by the number of Demand Resource On-Peak Hours in the month; or (ii) the sum of the Seasonal Peak Demand Resource's electrical energy reduction during Demand Resource Seasonal Peak Hours in the month divided by the number of Demand Resource Seasonal Peak Hours in the month. The On-Peak Demand Resource's or Seasonal Peak Demand Resource's electrical energy reduction and Average Hourly Load Reduction shall be determined consistent with the resource's Measurement and Verification Plan, which shall be reviewed by the ISO to ensure consistency with the measurement and verification requirements, as described in Section III.13.1.4.3 of Market Rule 1 and the ISO New England Manuals.

Average Hourly Output is either: (i) the sum of the On-Peak Demand Resource's electrical energy output during Demand Resource On-Peak Hours in the month divided by the number of Demand Resource On-Peak Hours in the month; or (ii) the sum of the Seasonal Peak Demand Resource's electrical energy output during Demand Resource Seasonal Peak Hours in the month divided by the number of Demand Resource Seasonal Peak Hours in the month. Electrical energy output and Average Hourly Output shall be determined consistent with the resource's Measurement and Verification Plan, which shall be reviewed by the ISO to ensure consistency with the measurement and verification requirements, as described in Section III.13.1.4.3 of Market Rule 1 and the ISO New England Manuals.

Average Monthly PER is calculated in accordance with Section III.13.7.1.2.2 of Market Rule 1.

Backstop Transmission Solution is a solution proposed: (i) to address a reliability or market efficiency need identified by the ISO in a Needs Assessment reported by the ISO pursuant to Section 4.1(i) of Attachment K to the ISO OATT, (ii) by the PTO or PTOs with an obligation under Schedule 3.09(a) of the TOA to address the identified need; and (iii) in circumstances in which the competitive solution process specified in Section 4.3 of Attachment K to the ISO OATT will be utilized.

Bankruptcy Code is the United States Bankruptcy Code.

Bankruptcy Event occurs when a Covered Entity files a voluntary or involuntary petition in bankruptcy or commences a proceeding under the United States Bankruptcy Code or any other applicable law concerning insolvency, reorganization or bankruptcy by or against such Covered Entity as debtor.

Bilateral Contract (BC) is any of the following types of contracts: Internal Bilateral for Load, Internal Bilateral for Market for Energy, and External Transactions.

Bilateral Contract Block-Hours are Block-Hours assigned to the seller and purchaser of an Internal Bilateral for Load, Internal Bilateral for Market for Energy and External Transactions; provided, however, that only those contracts which apply to the Real-Time Energy Market will accrue Block-Hours.

Binary Storage DARD is a DARD that participates in the New England Markets as part of a Binary Storage Facility, as described in Section III.1.10.6 of Market Rule 1.

Binary Storage Facility is a type of Electric Storage Facility, as described in Section III.1.10.6 of Market Rule 1.

Blackstart Capability Test is the test, required by ISO New England Operating Documents, of a resource's capability to provide Blackstart Service.

Blackstart Capital Payment is the annual compensation, as calculated pursuant to Section 5.1, or as referred to in Section 5.2, of Schedule 16 to the OATT, for a Designated Blackstart Resource's Blackstart Equipment capital costs associated with the provision of Blackstart Service (excluding the capital costs associated with compliance with NERC Critical Infrastructure Protection Reliability Standards as part of Blackstart Service).

Blackstart Equipment is any equipment that is solely necessary to enable the Designated Blackstart Resource to provide Blackstart Service and is not required to provide other products or services under the Tariff.

Blackstart O&M Payment is the annual Blackstart O&M compensation calculated under either Section 5.1 or 5.2 of Schedule 16 of the OATT, as applicable.

Blackstart Owner is the Market Participant who is authorized on behalf of the Generator Owner(s) to offer or operate the resource as a Designated Blackstart Resource and is authorized to commit the resource to provide Blackstart Service.

Blackstart Service is the Ancillary Service described in Section II.47 of the Tariff and Schedule 16 of the OATT.

Blackstart Service Commitment is the commitment by a Blackstart Owner for its resource to provide Blackstart Service and the acceptance of that commitment by the ISO, in the manner detailed in ISO New England Operating Procedure No. 11 – Designated Blackstart Resource Administration (OP 11), and which includes a commitment to provide Blackstart Service established under Operating Procedure 11 – Designated Blackstart Resource Administration (OP11).

Blackstart Service Minimum Criteria are the minimum criteria that a Blackstart Owner and its resource must meet in order to establish and maintain a resource as a Designated Blackstart Resource.

Blackstart Standard Rate Payment is the formulaic rate of monthly compensation, as calculated pursuant to Section 5 of Schedule 16 to the OATT, paid to a Blackstart Owner for the provision of Blackstart Service from a Designated Blackstart Resource.

Blackstart Station is comprised of (i) a single Designated Blackstart Resource or (ii) two or more Designated Blackstart Resources that share Blackstart Equipment.

Blackstart Station-specific Rate Payment is the Commission-approved compensation, as calculated pursuant to Section 5.2 of Schedule 16 to the OATT, paid to a Blackstart Owner on a monthly basis for the provision of Blackstart Service by Designated Blackstart Resources located at a specific Blackstart Station.

Blackstart Station-specific Rate Capital Payment is a component of the Blackstart Station-specific Rate Payment that reflects a Blackstart Station's capital Blackstart Equipment costs associated with the provision of Blackstart Service (excluding the capital costs associated with compliance with NERC Critical Infrastructure Protection Reliability Standards as part of Blackstart Service).

Block is defined as follows: (1) With respect to Bilateral Contracts, a Bilateral Contract administered by the ISO for an hour; (2) with respect to Supply Offers administered by the ISO, a quantity with a related price for Energy (Supply Offers for Energy may contain multiple sets of quantity and price pairs for each hour); (3) with respect to Demand Bids administered by the ISO, a quantity with a related price for Energy (Demand Bids for Energy may contain multiple sets of quantity and price pairs for each hour); (4) with respect to Increment Offers administered by the ISO, a quantity with a related price for Energy (Increment Offers for Energy may contain multiple sets of quantity and price pairs for each hour); (5) with respect to Decrement Bids administered by the ISO, a quantity with a related price for Energy (Decrement Bids for Energy may contain multiple sets of quantity and price pairs for each hour); (6) with respect to Asset Related Demand bids administered by the ISO, a quantity with a related price for Energy (Asset Related Demand bids may contain multiple sets of quantity and price pairs for each hour); and (7) with respect to Demand Reduction Offers administered by the ISO, a quantity of reduced demand with a related price (Demand Reduction Offers may contain multiple sets of quantity and price pairs for the day).

Block-Hours are the number of Blocks administered for a particular hour.

Budget and Finance Subcommittee is a subcommittee of the Participants Committee, the responsibilities of which are specified in Section 8.4 of the Participants Agreement.

Business Day is any day other than a Saturday or Sunday or ISO holidays as posted by the ISO on its website.

Cancelled Start NCPC Credit is an NCPC Credit calculated pursuant to Appendix F to Market Rule 1.

Capability Demonstration Year is the one year period from September 1 through August 31.

Capacity Acquiring Resource is a resource that is seeking to acquire a Capacity Supply Obligation through: (1) a Capacity Supply Obligation Bilateral, as described in Section III.13.5.1, or; (2) an annual or monthly reconfiguration auction, as described in Section III.13.4.

Capacity Balancing Ratio is a ratio used in calculating the Capacity Performance Payment in the Forward Capacity Market, as described in Section III.13.7.2.3 of Market Rule 1.

Capacity Base Payment is the portion of revenue received in the Forward Capacity Market as described in Section III.13.7.1 of Market Rule 1.

Capacity Capability Interconnection Standard has the meaning specified in Schedule 22, Schedule 23, and Schedule 25 of the OATT.

Capacity Clearing Price is the clearing price for a Capacity Zone for a Capacity Commitment Period resulting from the Forward Capacity Auction conducted for that Capacity Commitment Period, as determined in accordance with Section III.13.2.7 of Market Rule 1.

Capacity Commitment Period is the one-year period from June 1 through May 31 for which obligations are assumed and payments are made in the Forward Capacity Market.

Capacity Cost (CC) is one of four forms of compensation that may be paid to resources providing VAR Service under Schedule 2 of the OATT.

Capacity Export Through Import Constrained Zone Transaction is defined in Section III.1.10.7(f)(i) of Market Rule 1.

Capacity Load Obligation is the quantity of capacity for which a Market Participant is financially responsible as described in Section III.13.7.5.2 of Market Rule 1.

Capacity Load Obligation Acquiring Participant is a load serving entity or any other Market Participant seeking to acquire a Capacity Load Obligation through a Capacity Load Obligation Bilateral, as described in Section III.13.5.2 of Market Rule 1.

Capacity Network Import Capability (CNI Capability) is as defined in Section I of Schedule 25 of the OATT.

Capacity Network Import Interconnection Service (CNI Interconnection Service) is as defined in Section I of Schedule 25 of the OATT.

Capacity Load Obligation Bilateral is a bilateral contract through which a Market Participant may transfer all or a portion of its Capacity Load Obligation to another entity, as described in Section III.13.5 of Market Rule 1.

Capacity Load Obligation Transferring Participant is an entity that has a Capacity Load Obligation and is seeking to shed such obligation through a Capacity Load Obligation Bilateral, as described in Section III.13.5.2 of Market Rule 1.

Capacity Network Resource (CNR) is defined in Section I of Schedule 22 and Attachment 1 to Schedule 23 of the OATT.

Capacity Network Resource Interconnection Service (CNR Interconnection Service) is defined in Section I of Schedule 22 and Attachment 1 to Schedule 23 of the OATT.

Capacity Performance Bilateral is a transaction for transferring Capacity Performance Score, as described in Section III.13.5.3 of Market Rule 1.

Capacity Performance Payment is the performance-dependent portion of revenue received in the Forward Capacity Market, as described in Section III.13.7.2 of Market Rule 1.

Capacity Performance Payment Rate is a rate used in calculating Capacity Performance Payments, as described in Section III.13.7.2.5 of Market Rule 1.

Capacity Performance Score is a figure used in determining Capacity Performance Payments, as described in Section III.13.7.2.4 of Market Rule 1.

Capacity Rationing Rule addresses whether offers and bids in a Forward Capacity Auction may be rationed, as described in Section III.13.2.6 of Market Rule 1.

Capacity Scarcity Condition is a period during which performance is measured in the Forward Capacity Market, as described in Section III.13.7.2.1 of Market Rule 1.

Capacity Scarcity Condition is a period during which performance is measured in the Forward Capacity Market, as described in Section III.13.7.2.1 of Market Rule 1.

Capacity Supply Obligation is an obligation to provide capacity from a resource, or a portion thereof, to satisfy a portion of the Installed Capacity Requirement that is acquired through a Forward Capacity Auction in accordance with Section III.13.2, a reconfiguration auction in accordance with Section III.13.4, or a Capacity Supply Obligation Bilateral in accordance with Section III.13.5.1 of Market Rule 1.

Capacity Supply Obligation Bilateral is a bilateral contract through which a Market Participant may transfer all or a part of its Capacity Supply Obligation to another entity, as described in Section III.13.5.1 of Market Rule 1.

Capacity Transfer Rights (CTRs) are calculated in accordance with Section III.13.7.5.4.

Capacity Transferring Resource is a resource that has a Capacity Supply Obligation and is seeking to shed such obligation, or a portion thereof, through: (1) a Capacity Supply Obligation Bilateral, as described in Section III.13.5.1, or; (2) an annual or monthly reconfiguration auction, as described in Section III.13.4.

Capacity Zone is a geographic sub-region of the New England Control Area as determined in accordance with Section III.12.4 of Market Rule 1.

Capacity Zone Demand Curves are the demand curves used in the Forward Capacity Market for a Capacity Zone as specified in Sections III.13.2.2.2 and III.13.2.2.3.

Capital Funding Charge (CFC) is defined in Section IV.B.2 of the Tariff.

CARL Data is Control Area reliability data submitted to the ISO to permit an assessment of the ability of an external Control Area to provide energy to the New England Control Area in support of capacity offered to the New England Control Area by that external Control Area.

Category B Designated Blackstart Resource has the same meaning as Designated Blackstart Resource.

Charge is a sum of money due from a Covered Entity to the ISO, either in its individual capacity or as billing and collection agent for NEPOOL pursuant to the Participants Agreement.

CLAIM10 is the value, expressed in megawatts, calculated pursuant to Section III.9.5.3 of the Tariff.

CLAIM30 is the value, expressed in megawatts, calculated pursuant to Section III.9.5.3 of the Tariff.

Claimed Capability Audit is performed to determine the real power output capability of a Generator Asset or the demand reduction capability of a Demand Response Resource.

Cluster Enabling Transmission Upgrade (CETU) has the meaning specified in Section I of Schedule 22, Attachment 1 to Schedule 23, and Section I of Schedule 25 of the OATT.

Cluster Enabling Transmission Upgrade Regional Planning Study (CRPS) has the meaning specified in Section I of Schedule 22, Attachment 1 to Schedule 23, and Section I of Schedule 25 of the OATT.

Cluster Entry Deadline has the meaning specified in Section I of Schedule 22, Attachment 1 to Schedule 23, and Section I of Schedule 25 of the OATT.

Cluster Interconnection System Impact Study (CSIS) has the meaning specified in Section I of Schedule 22, Attachment 1 to Schedule 23, and Section I of Schedule 25 of the OATT.

Clustering has the meaning specified in Section I of Schedule 22, Attachment 1 to Schedule 23, and Section I of Schedule 25 of the OATT.

CNR Capability is defined in Section I of Schedule 22 and Attachment 1 to Schedule 23 of the OATT.

Coincident Peak Contribution is a Market Participant's share of the New England Control Area coincident peak demand for the prior calendar year as determined prior to the start of each Capacity Commitment Period, which reflects the sum of the prior year's annual coincident peak contributions of the customers served by the Market Participant at each Load Asset. Daily Coincident Peak Contribution

values shall be submitted by the Assigned Meter Reader or Host Participant by the meter reading deadline to the ISO.

Commercial Capacity is capacity that has achieved FCM Commercial Operation.

Commission is the Federal Energy Regulatory Commission.

Commitment Period is (i) for a Day-Ahead Energy Market commitment, a period of one or more contiguous hours for which a Resource is cleared in the Day-Ahead Energy Market, and (ii) for a Real-Time Energy Market commitment, the period of time for which the ISO indicates the Resource is being committed when it issues the Dispatch Instruction. If the ISO does not indicate the period of time for which the Resource is being committed in the Real-Time Energy Market, then the Commitment Period is the Minimum Run Time for an offline Resource and one hour for an online Resource.

Common Costs are those costs associated with a Station that are avoided only by the clearing of the Static De-List Bids, the Permanent De-List Bids, or the Retirement De-List Bids of all the Existing Generating Capacity Resources comprising the Station.

Completed Application is an Application that satisfies all of the information and other requirements of the OATT, including any required deposit.

Compliance Effective Date is the date upon which the changes in the predecessor NEPOOL Open Access Transmission Tariff which have been reflected herein to comply with the Commission's Order of April 20, 1998 became effective.

Composite FCM Transaction is a transaction for separate resources seeking to participate as a single composite resource in a Forward Capacity Auction in which multiple Designated FCM Participants provide capacity, as described in Section III.13.1.5 of Market Rule 1.

Conditional Qualified New Resource is defined in Section III.13.1.1.2.3(f) of Market Rule 1.

Confidential Information is defined in Section 2.1 of the ISO New England Information Policy, which is Attachment D to the Tariff.

Confidentiality Agreement is Attachment 1 to the ISO New England Billing Policy.

Congestion is a condition of the New England Transmission System in which transmission limitations prevent unconstrained regional economic dispatch of the power system. Congestion is the condition that results in the Congestion Component of the Locational Marginal Price at one Location being different from the Congestion Component of the Locational Marginal Price at another Location during any given hour of the dispatch day in the Day-Ahead Energy Market or Real-Time Energy Market.

Congestion Component is the component of the nodal price that reflects the marginal cost of congestion at a given Node or External Node relative to the reference point. When used in connection with Zonal Price and Hub Price, the term Congestion Component refers to the Congestion Components of the nodal prices that comprise the Zonal Price and Hub Price weighted and averaged in the same way that nodal prices are weighted to determine Zonal Price and averaged to determine the Hub Price.

Congestion Cost is the cost of congestion as measured by the difference between the Congestion Components of the Locational Marginal Prices at different Locations and/or Reliability Regions on the New England Transmission System.

Congestion Paying LSE is, for the purpose of the allocation of FTR Auction Revenues to ARR Holders as provided for in Appendix C of Market Rule 1, a Market Participant or Non-Market Participant Transmission Customer that is responsible for paying for Congestion Costs as a Transmission Customer paying for Regional Network Service under the Transmission, Markets and Services Tariff, unless such Transmission Customer has transferred its obligation to supply load in accordance with ISO New England System Rules, in which case the Congestion Paying LSE shall be the Market Participant supplying the transferred load obligation. The term Congestion Paying LSE shall be deemed to include, but not be limited to, the seller of internal bilateral transactions that transfer Real-Time Load Obligations under the ISO New England System Rules.

Congestion Revenue Fund is the amount available for payment of target allocations to FTR Holders from the collection of Congestion Cost.

Congestion Shortfall means congestion payments exceed congestion charges during the billing process in any billing period.

Contingency Reserve has the meaning specified in the Glossary of Terms Used in NERC Reliability Standards.

Contingency Reserve Restoration Period has the meaning specified in the Glossary of Terms Used in NERC Reliability Standards.

Continuous Storage ATRR is an ATRR that participates in the New England Markets as part of a Continuous Storage Facility, as described in Section III.1.10.6 of Market Rule 1.

Continuous Storage DARD is a DARD that participates in the New England Markets as part of a Continuous Storage Facility, as described in Section III.1.10.6 of Market Rule 1.

Continuous Storage Generator Asset is a Generator Asset that participates in the New England Markets as part of a Continuous Storage Facility, as described in Section III.1.10.6 of Market Rule 1.

Continuous Storage Facility is a type of Electric Storage Facility, as described in Section III.1.10.6 of Market Rule 1.

Control Agreement is the document posted on the ISO website that is required if a Market Participant's cash collateral is to be invested in BlackRock funds.

Control Area is an electric power system or combination of electric power systems to which a common automatic generation control scheme is applied in order to:

(1) match, at all times, the power output of the generators within the electric power system(s) and capacity and energy purchased from entities outside the electric power system(s), with the load within the electric power system(s);

(2) maintain scheduled interchange with other Control Areas, within the limits of Good Utility Practice;

(3) maintain the frequency of the electric power system(s) within reasonable limits in accordance with Good Utility Practice and the criteria of the applicable regional reliability council or the North American Electric Reliability Corporation; and

(4) provide sufficient generating capacity to maintain operating reserves in accordance with Good Utility Practice.

Controllable Behind-the-Meter Generation means generation whose output can be controlled located at the same facility as a DARD or a Demand Response Asset, excluding: (1) generators whose output is separately metered and reported and (2) generators that cannot operate electrically synchronized to, and that are operated only when the facility loses its supply of power from, the New England Transmission System, or when undergoing related testing.

Coordinated External Transaction is an External Transaction at an external interface for which the enhanced scheduling procedures in Section III.1.10.7.A are implemented. A transaction to wheel energy into, out of or through the New England Control Area is not a Coordinated External Transaction.
Coordinated Transaction Scheduling means the enhanced scheduling procedures set forth in Section III.1.10.7.A.

Correction Limit means the date that is one hundred and one (101) calendar days from the last Operating Day of the month to which the data applied. As described in Section III.3.6.1 of Market Rule 1, this will be the period during which meter data corrections must be submitted unless they qualify for submission as a Requested Billing Adjustment under Section III.3.7 of Market Rule 1.

Cost of Energy Consumed (CEC) is one of four forms of compensation that may be paid to resources providing VAR Service under Schedule 2 of the OATT.

Cost of Energy Produced (CEP) is one of four forms of compensation that may be paid to resources providing VAR Service under Schedule 2 of the OATT.

Cost of New Entry (CONE) is the estimated cost of new entry ($/kW-month) for a capacity resource that is determined by the ISO for each Forward Capacity Auction pursuant to Section III.13.2.4.

Counterparty means the status in which the ISO acts as the contracting party, in its name and own right and not as an agent, to an agreement or transaction with a Customer (including assignments involving Customers) involving sale to the ISO, and/or purchase from the ISO, of Regional Transmission Service and market and other products and services, and other transactions and assignments involving Customers, all as described in the Tariff.

Covered Entity is defined in the ISO New England Billing Policy.

Credit Coverage is third-party credit protection obtained by the ISO, in the form of credit insurance coverage, a performance or surety bond, or a combination thereof.

Credit Qualifying means a Rated Market Participant that has an Investment Grade Rating and an Unrated Market Participant that satisfies the Credit Threshold.

Credit Threshold consists of the conditions for Unrated Market Participants outlined in Section II.B.2 of the ISO New England Financial Assurance Policy.

Critical Energy Infrastructure Information (CEII) is defined in Section 3.0(j) of the ISO New England Information Policy, which is Attachment D to the Tariff.

Current Ratio is, on any date, all of a Market Participant's or Non-Market Participant Transmission Customer's current assets divided by all of its current liabilities, in each case as shown on the most recent financial statements provided by such Market Participant or Non-Market Participant Transmission Customer to the ISO.

Curtailment is a reduction in the dispatch of a transaction that was scheduled, using transmission service, in response to a transfer capability shortage as a result of system reliability conditions.

Customer is a Market Participant, a Transmission Customer or another customer of the ISO.

Data Reconciliation Process means the process by which meter reconciliation and data corrections that are discovered by Governance Participants after the Invoice has been issued for a particular month or that are discovered prior to the issuance of the Invoice for the relevant month but not included in that Invoice or in the other Invoices for that month and are reconciled by the ISO on an hourly basis based on data submitted to the ISO by the Host Participant Assigned Meter Reader or Assigned Meter Reader.

Day-Ahead is the calendar day immediately preceding the Operating Day.

Day-Ahead Adjusted Load Obligation is defined in Section III.3.2.1(a)(1) of Market Rule 1.

Day-Ahead Ancillary Services means Day-Ahead Generation Contingency Reserve, Day-Ahead Replacement Energy Reserve, and Day-Ahead Energy Imbalance Reserve.

Day-Ahead Congestion Revenue is defined in Section III.3.2.1(i) of Market Rule 1.

Day-Ahead Demand Reduction Obligation is defined in Section III.3.2.1(a)(1) of Market Rule 1.

Day-Ahead Energy Imbalance Reserve is a form of reserve capability that is procured in the Day-Ahead Energy Market to help satisfy the Forecast Energy Requirement Demand Quantity described in Section III.1.8.6 of Market Rule 1.

Day-Ahead Energy Imbalance Reserve Demand Quantity is described in Section III.1.8.5(f) of Market Rule 1.

Day-Ahead Energy Imbalance Reserve Obligation is defined in Section III.3.2.1(a)(2) of Market Rule 1.

Day-Ahead Energy Market means: (i) prior to June 1, 2024, the schedule of commitments for the purchase or sale of energy, purchase of demand reductions, payment of Congestion Costs, and payment for losses developed by the ISO as a result of the offers and specifications submitted in accordance with Section III.1.10 of Market Rule 1, and (ii) commencing on June 1, 2024, the schedule of commitments for the purchase or sale of energy, the sale of ancillary services, purchase of demand reductions, payment of Congestion Costs, and payment for losses developed by the ISO as a result of the offers and specifications submitted in accordance with Sections III.1.8 and III.1.10 of Market Rule 1.

Day-Ahead Energy Market Congestion Charge/Credit is defined in Section III.3.2.1(f) of Market Rule 1.

Day-Ahead Energy Market Energy Charge/Credit is defined in Section III.3.2.1(f) of Market Rule 1.

Day-Ahead Energy Market Loss Charge/Credit is defined in Section III.3.2.1(f) of Market Rule 1.

Day-Ahead Energy Market NCPC Credit is an NCPC Credit calculated pursuant to Appendix F to Market Rule 1.

Day-Ahead External Transaction Export and Decrement Bid NCPC Credit is an NCPC Credit calculated pursuant to Appendix F to Market Rule 1.

Day-Ahead External Transaction Import and Increment Offer NCPC Credit is an NCPC Credit calculated pursuant to Appendix F to Market Rule 1.

Day-Ahead Four-Hour Reserve is a form of reserve capability that is procured in the Day-Ahead Energy Market based on the system-wide requirements described in Section III.1.8.5 of Market Rule 1.

Day-Ahead Four-Hour Reserve Obligation is defined in Section III.3.2.1(a)(2) of Market Rule 1.

Day-Ahead Generation Contingency Reserve means Day-Ahead Ten-Minute Spinning Reserve, Day-Ahead Ten-Minute Non-Spinning Reserve, and Day-Ahead Thirty-Minute Operating Reserve.

Day-Ahead Generation Obligation is defined in Section III.3.2.1(a)(1) of Market Rule 1.

Day-Ahead Load Obligation is defined in Section III.3.2.1(a)(1) of Market Rule 1.

Day-Ahead Locational Adjusted Net Interchange is defined in Section III.3.2.1(a)(1) of Market Rule 1.

Day-Ahead Loss Charges or Credits is defined in Section III.3.2.1(k) of Market Rule 1.

Day-Ahead Loss Revenue is defined in Section III.3.2.1(j) of Market Rule 1.

Day-Ahead Ninety-Minute Reserve is a form of reserve capability that is procured in the Day-Ahead Energy Market based on the system-wide requirements described in Section III.1.8.5 of Market Rule 1.

Day-Ahead Ninety-Minute Reserve Obligation is defined in Section III.3.2.1(a)(2) of Market Rule 1.

Day-Ahead Prices means the Locational Marginal Prices resulting from the Day-Ahead Energy Market, and commencing on June 1, 2024, the additional prices resulting from the Day-Ahead Energy Market described in Section III.2.6.2 of Market Rule 1.

Day-Ahead Replacement Energy Reserve means Day-Ahead Ninety-Minute Reserve and Day-Ahead Four-Hour Reserve.

Day-Ahead Ten-Minute Non-Spinning Reserve is a form of ten-minute reserve capability that is procured in the Day-Ahead Energy Market based on the system-wide requirements described in Section III.1.8.5 of Market Rule 1.

Day-Ahead Ten-Minute Non-Spinning Reserve Obligation is defined in Section III.3.2.1(a)(2) of Market Rule 1.

Day-Ahead Ten-Minute Spinning Reserve is a form of ten-minute reserve capability that is procured in the Day-Ahead Energy Market based on the system-wide requirements described in Section III.1.8.5 of Market Rule 1.

Day-Ahead Ten-Minute Spinning Reserve Demand Quantity is described in Section III.1.8.5(a) of Market Rule 1.

Day-Ahead Ten-Minute Spinning Reserve Obligation is defined in Section III.3.2.1(a)(2) of Market Rule 1.

Day-Ahead Thirty-Minute Operating Reserve is a form of reserve capability that is procured in the Day-Ahead Energy Market based on the system-wide requirements described in Section III.1.8.5 of Market Rule 1.

Day-Ahead Thirty-Minute Operating Reserve Obligation is defined in Section III.3.2.1(a)(2) of Market Rule 1.

Day-Ahead Total Four-Hour Reserve Demand Quantity is described in Section III.1.8.5(e) of Market Rule 1.

Day-Ahead Total Ninety-Minute Reserve Demand Quantity is described in Section III.1.8.5(d) of Market Rule 1.

Day-Ahead Total Ten-Minute Reserve Demand Quantity is described in Section III.1.8.5(b) of Market Rule 1.

Day-Ahead Total Thirty-Minute Operating Reserve Demand Quantity is described in Section III.1.8.5(c) of Market Rule 1.

DDP Dispatchable Resource is any Dispatchable Resource that the ISO dispatches using Desired Dispatch Points in the Resource's Dispatch Instructions.

Debt-to-Total Capitalization Ratio is, on any date, a Market Participant's or Non-Market Participant Transmission Customer's total debt (including all current borrowings) divided by its total shareholders' equity plus total debt, in each case as shown on the most recent financial statements provided by such Market Participant or Non-Market Participant Transmission Customer to the ISO.

Decrement Bid means a bid to purchase energy at a specified Location in the Day-Ahead Energy Market which is not associated with a physical load. An accepted Decrement Bid results in scheduled load at the specified Location in the Day-Ahead Energy Market.

Default Amount is all or any part of any amount due to be paid by any Covered Entity that the ISO, in its reasonable opinion, believes will not or has not been paid when due (other than in the case of a payment dispute for any amount due for transmission service under the OATT).

Default Period is defined in Section 3.3.h(i) of the ISO New England Billing Policy.

Delivering Party is the entity supplying capacity and/or energy to be transmitted at Point(s) of Receipt under the OATT.

Demand Bid means a request to purchase an amount of energy, at a specified Location, or an amount of energy at a specified price, that is associated with a physical load. A cleared Demand Bid in the Day-Ahead Energy Market results in scheduled load at the specified Location. Demand Bids submitted for use in the Real-Time Energy Market are specific to Dispatchable Asset Related Demands only.

Demand Bid Block-Hours are the Block-Hours assigned to the submitting Customer for each Demand Bid.

Demand Bid Cap is $2,000/MWh.

Demand Capacity Resource means an Existing Demand Capacity Resource or a New Demand Capacity Resource. There are three Demand Capacity Resource types: Active Demand Capacity Resources, On-Peak Demand Resources, and Seasonal Peak Demand Resources.

Demand Designated Entity is the entity designated by a Market Participant to receive Dispatch Instructions for Demand Response Resources in accordance with the provisions set forth in ISO New England Operating Procedure No. 14.

Demand Reduction Offer is an offer by a Market Participant with a Demand Response Resource to reduce demand.

Demand Reduction Offer Block-Hours are Block-Hours assigned to the Lead Market Participant for each Demand Reduction Offer. Blocks of the Demand Reduction Offer in effect for each hour will be totaled to determine the quantity of Demand Reduction Offer Block-Hours for a given day. In the case that a Resource has a Real-Time unit status of “unavailable” for the entire day, that day will not contribute to the quantity of Demand Reduction Offer Block-Hours. However, if the Resource has at least one hour of the day with a unit status of “available,” the entire day will contribute to the quantity of Demand Reduction Offer Block-Hours.

Demand Reduction Threshold Price is a minimum offer price calculated pursuant to Section III.1.10.1A(f).

Demand Resource On-Peak Hours are hours ending 1400 through 1700, Monday through Friday on non-Demand Response Holidays during the months of June, July, and August and hours ending 1800 through 1900, Monday through Friday on non-Demand Response Holidays during the months of December and January.

Demand Resource Seasonal Peak Hours are those hours in which the actual, real-time hourly load, as measured using real-time telemetry (adjusted for transmission and distribution losses, and excluding load associated with Exports and Storage DARDs) for Monday through Friday on non-Demand Response Holidays, during the months of June, July, August, December, and January, as determined by the ISO, is

equal to or greater than 90% of the most recent 50/50 system peak load forecast, as determined by the ISO, for the applicable summer or winter season.

Demand Response Asset is an asset comprising the demand reduction capability of an individual end-use customer at a Retail Delivery Point or the aggregated demand reduction capability of multiple end-use customers from multiple delivery points (as described in Section III.8.1.1(f)) that has been registered in accordance with III.8.1.1.

Demand Response Available is the capability of the Demand Response Resource, in whole or in part, at any given time, to reduce demand in response to a Dispatch Instruction.

Demand Response Baseline is the expected baseline demand of an individual end-use metered customer or group of end-use metered customers as determined pursuant to Section III.8.2.

Demand Response Holiday is New Year's Day, Memorial Day, Independence Day, Labor Day, Veterans Day, Thanksgiving Day, and Christmas Day. If the holiday falls on a Saturday, the holiday will be observed on the preceding Friday; if the holiday falls on a Sunday, the holiday will be observed on the following Monday.

Demand Response Resource is an individual Demand Response Asset or aggregation of Demand Response Assets within a DRR Aggregation Zone that has been registered in accordance with Section III.8.1.2.

Demand Response Resource Notification Time is the period of time between the receipt of a startup Dispatch Instruction and the time the Demand Response Resource starts reducing demand.

Demand Response Resource Ramp Rate is the average rate, expressed in MW per minute, at which the Demand Response Resource can reduce demand.

Demand Response Resource Start-Up Time is the period of time between the time a Demand Response Resource starts reducing demand at the conclusion of the Demand Response Resource Notification Time and the time the resource can reach its Minimum Reduction and be ready for further dispatch by the ISO.

Designated Agent is any entity that performs actions or functions required under the OATT on behalf of the ISO, a Transmission Owner, a Schedule 20A Service Provider, an Eligible Customer, or a Transmission Customer.

Designated Blackstart Resource is a resource that meets the eligibility requirements specified in Schedule 16 of the OATT, which includes any resource referred to previously as a Category B Designated Blackstart Resource.

Designated Entity is the entity designated by a Market Participant to receive Dispatch Instructions for a Generator Asset and/or Dispatchable Asset Related Demand in accordance with the provisions set forth in ISO New England Operating Procedure No. 14.

Designated FCM Participant is any Lead Market Participant, including any Provisional Member that is a Lead Market Participant, transacting in any Forward Capacity Auction, reconfiguration auctions or Capacity Supply Obligation Bilateral for capacity that is otherwise required to provide additional financial assurance under the ISO New England Financial Assurance Policy.

Designated FTR Participant is a Market Participant, including FTR-Only Customers, transacting in the FTR Auction that is otherwise required to provide additional financial assurance under the ISO New England Financial Assurance Policy.

Desired Dispatch Point (DDP) means the control signal, expressed in megawatts, transmitted to direct the output, consumption, or demand reduction level of each Generator Asset, Dispatchable Asset Related Demand, or Demand Response Resource dispatched by the ISO in accordance with the asset's Offer Data.

Direct Assignment Facilities are facilities or portions of facilities that are constructed for the sole use/benefit of a particular Transmission Customer requesting service under the OATT or a Generator Owner requesting an interconnection. Direct Assignment Facilities shall be specified in a separate agreement among the ISO, Interconnection Customer and Transmission Customer, as applicable, and the Transmission Owner whose transmission system is to be modified to include and/or interconnect with the Direct Assignment Facilities, shall be subject to applicable Commission requirements, and shall be paid for by the Customer in accordance with the applicable agreement and the Tariff.

Directly Metered Assets are specifically measured by OP-18 compliant metering as currently described in Section IV (Metering and Recording for Settlements) of OP-18. Directly Metered Assets include all Tie-Line Assets, all Generator Assets, as well as some Load Assets. Load Assets for which the Host Participant is not the Assigned Meter Reader are considered Directly Metered Assets. In addition, the Host Participant Assigned Meter Reader determines which additional Load Assets are considered Directly Metered Assets and which ones are considered Profiled Load Assets based upon the Host Participant Assigned Meter Reader reporting systems and process by which the Host Participant Assigned Meter Reader allocates non-PTF losses.

Disbursement Agreement is the Rate Design and Funds Disbursement Agreement among the PTOs, as amended and restated from time to time.

Dispatch Instruction means directions given by the ISO to Market Participants, which may include instructions to start up, shut down, raise or lower generation, curtail or restore loads from Demand Response Resources, change External Transactions, or change the status or consumption of a Dispatchable Asset Related Demand in accordance with the Supply Offer, Demand Bid, or Demand Reduction Offer parameters. Such instructions may also require a change to the operation of a Pool Transmission Facility. Such instructions are given through either electronic or verbal means.

Dispatch Zone means a subset of Nodes located within a Load Zone established by the ISO for each Capacity Commitment Period pursuant to Section III.12.4A.

Dispatchable Asset Related Demand (DARD) is an Asset Related Demand that is capable of having its energy consumption modified in Real-Time in response to Dispatch Instructions. A DARD must be capable of receiving and responding to electronic Dispatch Instructions, must be able to increase or decrease energy consumption between its Minimum Consumption Limit and Maximum Consumption Limit in accordance with Dispatch Instructions, and must meet the technical requirements specified in the ISO New England Operating Procedures and Manuals.

Dispatchable Resource is any Generator Asset, Dispatchable Asset Related Demand, Demand Response Resource, or, with respect to the Regulation Market only, Alternative Technology Regulation Resource, that, during the course of normal operation, is capable of receiving and responding to electronic Dispatch Instructions in accordance with the parameters contained in the Resource’s Supply Offer, Demand Bid, Demand Reduction Offer or Regulation Service Offer. A Resource that is normally classified as a

Dispatchable Resource remains a Dispatchable Resource when it is temporarily not capable of receiving and responding to electronic Dispatch Instructions.

Dispute Representatives are defined in 6.5.c of the ISO New England Billing Policy.

Disputed Amount is a Covered Entity's disputed amount due on any fully paid monthly Invoice and/or any amount believed to be due or owed on a Remittance Advice, as defined in Section 6 of the ISO New England Billing Policy.

Disputing Party, for the purposes of the ISO New England Billing Policy, is any Covered Entity seeking to recover a Disputed Amount.

Distributed Generation means generation directly connected to end-use customer load and located behind the end-use customer's Retail Delivery Point that reduces the amount of energy that would otherwise have been produced on the electricity network in the New England Control Area, provided that the facility's Net Supply Capability is (i) less than 5 MW or (ii) less than or equal to the Maximum Facility Load, whichever is greater.

DRR Aggregation Zone is a Dispatch Zone entirely within a single Reserve Zone or Rest of System or, where a Dispatch Zone is not entirely within a single Reserve Zone or Rest of System, each portion of the Dispatch Zone demarcated by the Reserve Zone boundary.

Do Not Exceed (DNE) Dispatchable Generator is any Generator Asset that is dispatched using Do Not Exceed Dispatch Points in its Dispatch Instructions and meets the criteria specified in Section III.1.11.3(e).   Do Not Exceed Dispatchable Generators are Dispatchable Resources.

Do Not Exceed Dispatch Point is a Dispatch Instruction indicating a maximum output level that a DNE Dispatchable Generator must not exceed.

Dynamic De-List Bid is a bid that may be submitted by Existing Generating Capacity Resources, Existing Import Capacity Resources, and Existing Demand Capacity Resources in the Forward Capacity Auction below the Dynamic De-List Bid Threshold, as described in Section III.13.2.3.2(d) of Market Rule 1.

Dynamic De-List Bid Threshold is the price specified in Section III.13.1.2.3.1.A of Market Rule 1 associated with the submission of Dynamic De-List Bids in the Forward Capacity Auction.

EA Amount is defined in Section IV.B.2.2 of the Tariff.

Early Amortization Charge (EAC) is defined in Section IV.B.2 of the Tariff.

Early Amortization Working Capital Charge (EAWCC) is defined in Section IV.B.2 of the Tariff.

Early Payment Shortfall Funding Amount (EPSF Amount) is defined in Section IV.B.2.4 of the Tariff.

Early Payment Shortfall Funding Charge (EPSFC) is defined in Section IV.B.2 of the Tariff.

EAWW Amount is defined in Section IV.B.2.3 of the Tariff.

EBITDA-to-Interest Expense Ratio is, on any date, a Market Participant's or Non-Market Participant Transmission Customer's earnings before interest, taxes, depreciation and amortization in the most recent fiscal quarter divided by that Market Participant's or Non-Market Participant Transmission Customer's expense for interest in that fiscal quarter, in each case as shown on the most recent financial statements provided by such Market Participant or Non-Market Participant Transmission Customer to the ISO.

Economic Dispatch Point is the output, reduction, or consumption level to which a Resource would have been dispatched, based on the Resource's Supply Offer, Demand Reduction Offer, or Demand Bid and the Real-Time Price, and taking account of any operating limits, had the ISO not dispatched the Resource to another Desired Dispatch Point.

Economic Maximum Limit or Economic Max is the maximum available output, in MW, of a Generator Asset that a Market Participant offers to supply in the Day-Ahead Energy Market or Real-Time Energy Market, as reflected in the Generator Asset's Offer Data. This represents the highest MW output a Market Participant has offered for a Generator Asset for economic dispatch. A Market Participant must maintain an up-to-date Economic Maximum Limit (and where applicable, must provide the ISO with any telemetry required by ISO New England Operating Procedure No. 18 to allow the ISO to maintain an

updated Economic Maximum Limit) for all hours in which a Generator Asset has been offered into the Day-Ahead Energy Market or Real-Time Energy Market.

Economic Minimum Limit or Economic Min is (a) for a Generator Asset with an incremental heat rate, the maximum of: (i) the lowest sustainable output level as specified by physical design characteristics, environmental regulations or licensing limits; and (ii) the lowest sustainable output level at which a one MW increment increase in the output level would not decrease the incremental cost, calculated based on the incremental heat rate, of providing an additional MW of output, and (b) for a Generator Asset without an incremental heat rate, the lowest sustainable output level that is consistent with the physical design characteristics of the Generator Asset and with meeting all environmental regulations and licensing limits, and (c) for a Generator Asset undergoing Facility and Equipment Testing or auditing, the level to which the Generator Asset requests and is approved to operate or is directed to operate for purposes of completing the Facility and Equipment Testing or auditing, and (d) for Non-Dispatchable Resources the output level at which a Market Participant anticipates its Non-Dispatchable Resource will be available to operate based on fuel limitations, physical design characteristics, environmental regulations or licensing limits.

Economic Study is defined in Section 4.1(b) of Attachment K to the OATT.

Effective Offer is the Supply Offer, Demand Reduction Offer, or Demand Bid that is used for NCPC calculation purposes as specified in Section III.F.1(a).

EFT is electronic funds transfer.

Elective Transmission Upgrade is defined in Section I of Schedule 25 of the OATT.

Elective Transmission Upgrade Interconnection Customer is defined in Schedule 25 of the OATT.

Electric Reliability Organization (ERO) is defined in 18 C.F.R. § 39.1.

Electric Storage Facility is a storage facility that participates in the New England Markets as described in Section III.1.10.6 of Market Rule 1.

Eligible Customer is: (i) Any entity that is engaged, or proposes to engage, in the wholesale or retail electric power business is an Eligible Customer under the OATT. (ii) Any electric utility (including any power marketer), Federal power marketing agency, or any other entity generating electric energy for sale or for resale is an Eligible Customer under the OATT. Electric energy sold or produced by such entity may be electric energy produced in the United States, Canada or Mexico. However, with respect to transmission service that the Commission is prohibited from ordering by Section 212(h) of the Federal Power Act, such entity is eligible only if the service is provided pursuant to a state requirement that the Transmission Owner with which that entity is directly interconnected or the distribution company having the service territory in which that entity is located (if that entity is a retail customer) offer the unbundled transmission service or Local Delivery Service, or pursuant to a voluntary offer of such service by the Transmission Owner with which that entity is directly interconnected or the distribution company having the service territory in which that entity is located (if that entity is a retail customer). (iii) Any end user taking or eligible to take unbundled transmission service or Local Delivery Service pursuant to a state requirement that the Transmission Owner with which that end user is directly interconnected or the distribution company having the service territory in which that entity is located (if that entity is a retail customer) offer the transmission service or Local Delivery Service, or pursuant to a voluntary offer of such service by the Transmission Owner with which that end user is directly interconnected, or the distribution company having the service territory in which that entity is located (if that entity is a retail customer) is an Eligible Customer under the OATT.

Eligible FTR Bidder is an entity that has satisfied applicable financial assurance criteria, and shall not include the auctioneer, its Affiliates, and their officers, directors, employees, consultants and other representatives.

Emergency is an abnormal system condition on the bulk power systems of New England or neighboring Control Areas requiring manual or automatic action to maintain system frequency, or to prevent the involuntary loss of load, equipment damage, or tripping of system elements that could adversely affect the reliability of an electric system or the safety of persons or property; or a fuel shortage requiring departure from normal operating procedures in order to minimize the use of such scarce fuel; or a condition that requires implementation of Emergency procedures as defined in the ISO New England Manuals.

Emergency Condition means an Emergency has been declared by the ISO in accordance with the procedures set forth in the ISO New England Manuals and ISO New England Administrative Procedures.

Emergency Energy is energy transferred from one control area operator to another in an Emergency.

Emergency Minimum Limit or Emergency Min means the minimum output, in MWs, that a Generator Asset can deliver for a limited period of time without exceeding specified limits of equipment stability and operating permits.

EMS is energy management system.

End-of-Round Price is the lowest price associated with a round of a Forward Capacity Auction, as described in Section III.13.2.3.1 of Market Rule 1.

End User Participant is defined in Section 1 of the Participants Agreement.

Energy is power produced in the form of electricity, measured in kilowatthours or megawatthours.

Energy Administration Service (EAS) is the service provided by the ISO, as described in Schedule 2 of Section IV.A of the Tariff.

Energy Call Option Offer is a form of offer that may be submitted by Market Participants in the Day-Ahead Energy Market in accordance with Section III.1.8 of Market Rule 1, and that is used by the ISO to determine obligations for Day-Ahead Ancillary Services as defined in Section III.3.2.1(a)(2) of Market Rule 1.

Energy Call Option Strike Price is specified in Section III.1.8. 3 of Market Rule 1.

Energy Component means the Locational Marginal Price at the reference point.

Energy Efficiency is installed measures (e.g., products, equipment, systems, services, practices and/or strategies) on end-use customer facilities that reduce the total amount of electrical energy needed, while delivering a comparable or improved level of end-use service. Such measures include, but are not limited to, the installation of more energy efficient lighting, motors, refrigeration, HVAC equipment and control systems, envelope measures, operations and maintenance procedures, and industrial process equipment.

Energy Imbalance Service is the form of Ancillary Service described in Schedule 4 of the OATT.

Energy Market is, collectively, the Day-Ahead Energy Market and the Real-Time Energy Market.

Energy Non-Zero Spot Market Settlement Hours are the sum of the hours for which the Customer has a positive or negative Real-Time System Adjusted Net Interchange or for which the Customer has a positive or negative Real-Time Demand Reduction Obligation as determined by the ISO settlement process for the Energy Market.

Energy Offer Floor is negative $150/MWh.

Energy Transaction Units (Energy TUs) are the sum for the month for a Customer of Bilateral Contract Block-Hours, Demand Bid Block-Hours, Asset Related Demand Bid Block-Hours, Supply Offer Block-Hours, Demand Reduction Offer Block-Hours, and Energy Non-Zero Spot Market Settlement Hours.

Equipment Damage Reimbursement is the compensation paid to the owner of a Designated Blackstart Resource as specified in Section 5.5 of Schedule 16 to the OATT.

Equivalent Demand Forced Outage Rate (EFORd) means the portion of time a unit is in demand, but is unavailable due to forced outages.

Estimated Capacity Load Obligation is, for the purposes of the ISO New England Financial Assurance Policy, a Market Participant's share of Zonal Capacity Obligation from the latest available month, adjusted as appropriate to account for any relevant Capacity Load Obligation Bilaterals, HQICCs, and Self-Supplied FCA Resource designations for the applicable month.

Establish Claimed Capability Audit is the audit performed pursuant to Section III.1.5.1.2.

Excepted Transaction is a transaction specified in Section II.40 of the Tariff for the applicable period specified in that Section.

Existing Capacity Qualification Deadline is a deadline, specified in Section III.13.1.10 of Market Rule 1, for submission of certain qualification materials for the Forward Capacity Auction, as discussed in Section III.13.1 of Market Rule 1.

Existing Capacity Qualification Package is information submitted for certain existing resources prior to participation in the Forward Capacity Auction, as described in Section III.13.1 of Market Rule 1.

Existing Capacity Resource is any resource that does not meet any of the eligibility criteria to participate in the Forward Capacity Auction as a New Capacity Resource.

Existing Capacity Retirement Deadline is a deadline, specified in Section III.13.1.10 of Market Rule 1, for submission of certain qualification materials for the Forward Capacity Auction, as discussed in Section III.13.1 of Market Rule 1.

Existing Capacity Retirement Package is information submitted for certain existing resources prior to participation in the Forward Capacity Auction, as described in Section III.13.1 of Market Rule 1.

Existing Demand Capacity Resource is a type of Demand Capacity Resource participating in the Forward Capacity Market, as defined in Section III.13.1.4.2 of Market Rule 1.

Existing Generating Capacity Resource is a type of resource participating in the Forward Capacity Market, as defined in Section III.13.1.2.1 of Market Rule 1.

Existing Import Capacity Resource is a type of resource participating in the Forward Capacity Market, as defined in Section III.13.1.3.1 of Market Rule 1.

Expedited Study Request is defined in Section II.34.7 of the OATT.

Export-Adjusted LSR is as defined in Section III.12.4(b)(ii).

Export Bid is a bid that may be submitted by certain resources in the Forward Capacity Auction to export capacity to an external Control Area, as described in Section III.13.1.2.3.1.3 of Market Rule 1.

Exports are Real-Time External Transactions, which are limited to sales from the New England Control Area, for exporting energy out of the New England Control Area.

External Elective Transmission Upgrade (External ETU) is defined in Section I of Schedule 25 of the OATT.

External Market Monitor means the person or entity appointed by the ISO Board of Directors pursuant to Section III.A.1.2 of Appendix A of Market Rule 1 to carry out the market monitoring and mitigation functions specified in Appendix A and elsewhere in Market Rule 1.

External Node is a proxy bus or buses used for establishing a Locational Marginal Price for energy received by Market Participants from, or delivered by Market Participants to, a neighboring Control Area or for establishing Locational Marginal Prices associated with energy delivered through the New England Control Area by Non-Market Participants for use in calculating Non-Market Participant Congestion Costs and loss costs.

External Resource means a generation resource located outside the metered boundaries of the New England Control Area.

External Transaction is the import of external energy into the New England Control Area by a Market Participant or the export of internal energy out of the New England Control Area by a Market Participant in the Day-Ahead Energy Market and/or Real-Time Energy Market, or the wheeling of external energy through the New England Control Area by a Market Participant or a Non-Market Participant in the Real-Time Energy Market.

External Transaction Cap is $2,000/MWh for External Transactions other than Coordinated External Transactions and $1,000/MWh for Coordinated External Transactions.

External Transaction Floor is the Energy Offer Floor for External Transactions other than Coordinated External Transactions and negative $1,000/MWh for Coordinated External Transactions.

External Transmission Project is a transmission project comprising facilities located wholly outside the New England Control Area and regarding which an agreement has been reached whereby New England ratepayers will support all or a portion of the cost of the facilities.

Facilities Study is an engineering study conducted pursuant to the OATT by the ISO (or, in the case of Local Service or interconnections to Local Area Facilities as defined in the TOA, by one or more affected PTOs) or some other entity designated by the ISO in consultation with any affected Transmission Owner(s), to determine the required modifications to the PTF and Non-PTF, including the cost and

scheduled completion date for such modifications, that will be required to provide a requested transmission service or interconnection on the PTF and Non-PTF.

Facility and Equipment Testing means operation of a Resource to evaluate the functionality of the facility or equipment utilized in the operation of the facility.

Failure to Maintain Blackstart Capability is a failure of a Blackstart Owner or Designated Blackstart Resource to meet the Blackstart Service Minimum Criteria or Blackstart Service obligations, but does not include a Failure to Perform During a System Restoration event.

Failure to Perform During a System Restoration is a failure of a Blackstart Owner or Designated Blackstart Resource to follow ISO or Local Control Center dispatch instructions or perform in accordance with the dispatch instructions or the Blackstart Service Minimum Criteria and Blackstart Service obligations, described within the ISO New England Operating Documents, during a restoration of the New England Transmission System.

Fast Start Demand Response Resource is a Demand Response Resource that meets the following criteria: (i) Minimum Reduction Time does not exceed one hour; (ii) Minimum Time Between Reductions does not exceed one hour; (iii) Demand Response Resource Start-Up Time plus Demand Response Resource Notification Time does not exceed 30 minutes; (iv) has personnel available to respond to Dispatch Instructions or has automatic remote response capability; and (v) is capable of receiving and acknowledging a Dispatch Instruction electronically.

Fast Start Generator means a Generator Asset that the ISO can dispatch to an on-line or off-line state through electronic dispatch and that meets the following criteria: (i) Minimum Run Time does not exceed one hour; (ii) Minimum Down Time does not exceed one hour; (iii) cold Notification Time plus cold Start-Up Time does not exceed 30 minutes; (iv) available for dispatch (when it is either in an on-line or off-line state) and manned or has automatic remote dispatch capability; and (v) capable of receiving and acknowledging a start-up or shut-down Dispatch Instruction electronically.

FCA Cleared Export Transaction is defined in Section III.1.10.7(f)(ii) of Market Rule 1.

FCA Qualified Capacity is the Qualified Capacity that is used in a Forward Capacity Auction.

FCM Capacity Charge Requirements are calculated in accordance with Section VII.C of the ISO New England Financial Assurance Policy.

FCM Charge Rate is calculated in accordance with Section VII.C of the ISO New England Financial Assurance Policy.

FCM Commercial Operation is defined in Section III.13.3.8 of Market Rule 1.

FCM Deposit is calculated in accordance with Section VII.B.1 of the ISO New England Financial Assurance Policy.

FCM Financial Assurance Requirements are described in Section VII of the ISO New England Financial Assurance Policy.

Final Forward Reserve Obligation is calculated in accordance with Section III.9.8(a) of Market Rule 1.

Financial Assurance Default results from a Market Participant or Non-Market Participant Transmission Customer's failure to comply with the ISO New England Financial Assurance Policy.

Financial Assurance Obligations relative to the ISO New England Financial Assurance Policy are determined in accordance with Section III.A(v) of the ISO New England Financial Assurance Policy.

Financial Transmission Right (FTR) is a financial instrument that evidences the rights and obligations specified in Sections III.5.2.2 and III.7 of the Tariff.

Firm Point-To-Point Service is service which is arranged for and administered between specified Points of Receipt and Delivery in accordance with Part II.C of the OATT.

Firm Transmission Service is Regional Network Service, Through or Out Service, service for Excepted Transactions, firm MTF Service, firm OTF Service, and firm Local Service.

Flexible DNE Dispatchable Generator is any DNE Dispatchable Generator that meets the following criteria: (i) Minimum Run Time does not exceed one hour; (ii) Minimum Down Time does not exceed one hour; and (iii) cold Notification Time plus cold Start-Up Time does not exceed 30 minutes.

Force Majeure - An event of Force Majeure means any act of God, labor disturbance, act of the public enemy or terrorists, war, invasion, insurrection, riot, fire, storm or flood, ice, explosion, breakage or accident to machinery or equipment, any curtailment, order, regulation or restriction imposed by governmental military or lawfully established civilian authorities, or any other cause beyond the control of the ISO, a Transmission Owner, a Schedule 20A Service Provider, or a Customer, including without limitation, in the case of the ISO, any action or inaction by a Customer, a Schedule 20A Service Provider, or a Transmission Owner, in the case of a Transmission Owner, any action or inaction by the ISO, any Customer, a Schedule 20A Service Provider, or any other Transmission Owner, in the case of a Schedule 20A Service Provider, any action or inaction by the ISO, any Customer, a Transmission Owner, or any other Schedule 20A Service Provider, and, in the case of a Transmission Customer, any action or inaction by the ISO, a Schedule 20A Service Provider, or any Transmission Owner.

Forecast Energy Requirement Demand Quantity is described in Section III.1.8.6 of Market Rule 1.

Forecast Energy Requirement Price is determined in accordance with Section III.2.6.2(a) of Market Rule 1.

Formal Warning is defined in Section III.B.4.1.1 of Appendix B of Market Rule 1.

Formula-Based Sanctions are defined in Section III.B.4.1.3 of Appendix B of Market Rule 1.

Forward Capacity Auction (FCA) is the annual Forward Capacity Market auction process described in Section III.13.2 of Market Rule 1.

Forward Capacity Auction Starting Price is calculated in accordance with Section III.13.2.4 of Market Rule 1.

Forward Capacity Market (FCM) is the forward market for procuring capacity in the New England Control Area, as described in Section III.13 of Market Rule 1.

Forward Energy Inventory Election is the total MWh value for which a Market Participant elects to be compensated at the forward rate in the inventoried energy program as described in Section III.K.1(d) of Market Rule 1.

Forward LNG Inventory Election is the portion of a Market Participant's Forward Energy Inventory Election attributed to liquefied natural gas in the inventoried energy program as described in Section III.K.1(d) of Market Rule 1.

Forward Reserve means TMNSR and TMOR purchased by the ISO on a forward basis on behalf of Market Participants as provided for in Section III.9 of Market Rule 1.

Forward Reserve Assigned Megawatts is the amount of Forward Reserve, in megawatts, that a Market Participant assigns to eligible Forward Reserve Resources to meet its Forward Reserve Obligation as defined in Section III.9.4.1 of Market Rule 1.

Forward Reserve Auction is the periodic auction conducted by the ISO in accordance with Section III.9 of Market Rule 1 to procure Forward Reserve.

Forward Reserve Auction Offers are offers to provide Forward Reserve to meet system and Reserve Zone requirements as submitted by a Market Participant in accordance with Section III.9.3 of Market Rule 1.

Forward Reserve Charge is a Market Participant's share of applicable system and Reserve Zone Forward Reserve costs attributable to meeting the Forward Reserve requirement as calculated in accordance with Section III.9.9 of Market Rule 1.

Forward Reserve Clearing Price is the clearing price for TMNSR or TMOR, as applicable, for the system and each Reserve Zone resulting from the Forward Reserve Auction as defined in Section III.9.4 of Market Rule 1.

Forward Reserve Credit is the credit received by a Market Participant that is associated with that Market Participant's Final Forward Reserve Obligation as calculated in accordance with Section III.9.8 of Market Rule 1.

Forward Reserve Delivered Megawatts are calculated in accordance with Section III.9.6.5 of Market Rule 1.

Forward Reserve Delivery Period is defined in Section III.9.1 of Market Rule 1.

Forward Reserve Failure-to-Activate Megawatts are calculated in accordance with Section III.9.7.2(a) of Market Rule 1.

Forward Reserve Failure-to-Activate Penalty is the penalty associated with a Market Participant's failure to activate Forward Reserve when requested to do so by the ISO and is defined in Section III.9.7.2 of Market Rule 1.

Forward Reserve Failure-to-Activate Penalty Rate is specified in Section III.9.7.2 of Market Rule 1.

Forward Reserve Failure-to-Reserve, as specified in Section III.9.7.1 of Market Rule 1, occurs when a Market Participant's Forward Reserve Delivered Megawatts for a Reserve Zone in an hour is less than that Market Participant's Forward Reserve Obligation for that Reserve Zone in that hour. Under these circumstances the Market Participant pays a penalty based upon the Forward Reserve Failure-to-Reserve Penalty Rate and that Market Participant's Forward Reserve Failure-to-Reserve Megawatts.

Forward Reserve Failure-to-Reserve Megawatts are calculated in accordance with Section III.9.7.1(a) of Market Rule 1.

Forward Reserve Failure-to-Reserve Penalty is the penalty associated with a Market Participant's failure to reserve Forward Reserve and is defined in Section III.9.7.1 of Market Rule 1.

Forward Reserve Failure-to-Reserve Penalty Rate is specified in Section III.9.7.1(b)(ii) of Market Rule 1.

Forward Reserve Fuel Index is the index or set of indices used to calculate the Forward Reserve Threshold Price as defined in Section III.9.6.2 of Market Rule 1.

Forward Reserve Heat Rate is the heat rate as defined in Section III.9.6.2 of Market Rule 1 that is used to calculate the Forward Reserve Threshold Price.

Forward Reserve Market is a market for forward procurement of two reserve products, Ten-Minute Non-Spinning Reserve (TMNSR) and Thirty-Minute Operating Reserve (TMOR).

Forward Reserve MWs are those megawatts assigned to specific eligible Forward Reserve Resources which convert a Forward Reserve Obligation into a Resource-specific obligation.

Forward Reserve Obligation is a Market Participant's amount, in megawatts, of Forward Reserve that cleared in the Forward Reserve Auction and adjusted, as applicable, to account for bilateral transactions that transfer Forward Reserve Obligations.

Forward Reserve Obligation Charge is defined in Section III.10.4 of Market Rule 1.

Forward Reserve Offer Cap is $9,000/megawatt-month.

Forward Reserve Payment Rate is defined in Section III.9.8 of Market Rule 1.

Forward Reserve Procurement Period is defined in Section III.9.1 of Market Rule 1.

Forward Reserve Qualifying Megawatts refer to all or a portion of a Forward Reserve Resource's capability offered into the Real-Time Energy Market at energy offer prices above the applicable Forward Reserve Threshold Price that are calculated in accordance with Section III.9.6.4 of Market Rule 1.

Forward Reserve Resource is a Resource that meets the eligibility requirements defined in Section III.9.5.2 of Market Rule 1 that has been assigned Forward Reserve Obligation by a Market Participant.

Forward Reserve Threshold Price is the minimum price at which assigned Forward Reserve Megawatts are required to be offered into the Real-Time Energy Market as calculated in Section III.9.6.2 of Market Rule 1.

FTR Auction is the periodic auction of FTRs conducted by the ISO in accordance with Section III.7 of Market Rule 1.

FTR Auction Revenue is the revenue collected from the sale of FTRs in FTR Auctions. FTR Auction Revenue is payable to FTR Holders who submit their FTRs for sale in the FTR Auction in accordance with Section III.7 of Market Rule 1 and to ARR Holders and Incremental ARR Holders in accordance with Appendix C of Market Rule 1.

FTR Credit Test Percentage is calculated in accordance with Section III.B.1(b) of the ISO New England Financial Assurance Policy.

FTR Financial Assurance Requirements are described in Section VI of the ISO New England Financial Assurance Policy.

FTR Holder is an entity that acquires an FTR through the FTR Auction to Section III.7 of Market Rule 1 and registers with the ISO as the holder of the FTR in accordance with Section III.7 of Market Rule 1 and applicable ISO New England Manuals.

FTR-Only Customer is a Market Participant that transacts in the FTR Auction and that does not participate in other markets or programs of the New England Markets. References in this Tariff to a "Non-Market Participant FTR Customers" and similar phrases shall be deemed references to an FTR-Only Customer.

FTR Settlement Risk Financial Assurance is an amount of financial assurance required by a Designated FTR Participant for each bid submission into an FTR Auction and for each bid awarded to the individual participant in an FTR Auction. This amount is calculated pursuant to Section VI.A of the ISO New England Financial Assurance Policy.

GADS Data means data submitted to the NERC for collection into the NERC's Generating Availability Data System (GADS).

Gap Request for Proposals (Gap RFP) is defined in Section III.11 of Market Rule 1.

Gas Day means a period of 24 consecutive hours beginning at 0900 hrs Central Time.

Generating Capacity Resource means a New Generating Capacity Resource or an Existing Generating Capacity Resource.

Generator Asset is a device (or a collection of devices) that is capable of injecting real power onto the grid that has been registered as a Generator Asset in accordance with the Asset Registration Process.

Generator Imbalance Service is the form of Ancillary Service described in Schedule 10 of the OATT.

Generator Interconnection Related Upgrade is an addition to or modification of the New England Transmission System (pursuant to Section II.47.1, Schedule 22 or Schedule 23 of the OATT) to effect the interconnection of a new generating unit or an existing generating unit whose energy capability or capacity capability is being materially changed and increased whether or not the interconnection is being effected to meet the Capacity Capability Interconnection Standard or the Network Capability Interconnection Standard. As to Category A Projects (as defined in Schedule 11 of the OATT), a Generator Interconnection Related Upgrade also includes an upgrade beyond that required to satisfy the Network Capability Interconnection Standard (or its predecessor) for which the Generator Owner has committed to pay prior to October 29, 1998.

Generator Owner is the owner, in whole or part, of a generating unit whether located within or outside the New England Control Area.

Good Utility Practice means any of the practices, methods and acts engaged in or approved by a significant portion of the electric utility industry during the relevant time period, or any of the practices, methods and acts which, in the exercise of reasonable judgment in light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety and expedition. Good Utility Practice is not intended to be limited to the optimum practice, method, or act to the exclusion of all others, but rather includes all acceptable practices, methods, or acts generally accepted in the region, including those practices required by Federal Power Act Section 215(a)(4).

Governance Only Member is defined in Section 1 of the Participants Agreement.

Governance Participant is defined in the Participants Agreement.

Governing Documents, for the purposes of the ISO New England Billing Policy, are the Transmission, Markets and Services Tariff and ISO Participants Agreement.

Governing Rating is the lowest corporate rating from any Rating Agency for that Market Participant, or, if the Market Participant has no corporate rating, then the lowest rating from any Rating Agency for that Market Participant’s senior unsecured debt.

Grandfathered Agreements (GAs) is a transaction specified in Section II.45 for the applicable period specified in that Section.

Grandfathered Intertie Agreement (GIA) is defined pursuant to the TOA.

Handy-Whitman Index of Public Utility Construction Costs is the Total Other Production Plant index shown in the Cost Trends of Electric Utility Construction for the North Atlantic Region as published in the Handy-Whitman Index of Public Utility Construction Costs.

Highgate Transmission Facilities (HTF) are existing U. S.-based transmission facilities covered under the Agreement for Joint Ownership, Construction and Operation of the Highgate Transmission Interconnection dated as of August 1, 1984 including (1) the whole of a 200 megawatt high-voltage, back-to-back, direct-current converter facility located in Highgate, Vermont and (2) a 345 kilovolt transmission line within Highgate and Franklin, Vermont (which connects the converter facility at the U.S.-Canadian border to a Hydro-Quebec 120 kilovolt line in Bedford, Quebec). The HTF include any upgrades associated with increasing the capacity or changing the physical characteristics of these facilities as defined in the above stated agreement dated August 1, 1984 until the Operations Date, as defined in the TOA. The current HTF rating is a nominal 225 MW. The HTF are not defined as PTF. Coincident with the Operations Date and except as stipulated in Schedules, 9, 12, and Attachment F to the OATT, HTF shall be treated in the same manner as PTF for purposes of the OATT and all references to PTF in the OATT shall be deemed to apply to HTF as well. The treatment of the HTF is not intended to establish any binding precedent or presumption with regard to the treatment for other transmission facilities within the New England Transmission System (including HVDC, MTF, or Control Area Interties) for purposes of the OATT.

Host Participant or Host Utility is a Market Participant or a Governance Participant transmission or distribution provider that reconciles the loads within the metering domain with OP-18 compliant metering.

Hourly Charges are defined in Section 1.3 of the ISO New England Billing Policy.

Hourly PER is calculated in accordance with Section III.13.7.1.2.1 of Market Rule 1.

Hourly Requirements are determined in accordance with Section III.A(i) of the ISO New England Financial Assurance Policy.

Hourly Shortfall NCPC Credit is an NCPC Credit calculated pursuant to Appendix F to Market Rule 1.

Hub is a specific set of pre-defined Nodes for which a Locational Marginal Price will be calculated for the Day-Ahead Energy Market and Real-Time Energy Market and which can be used to establish a reference price for energy purchases and the transfer of Day-Ahead Adjusted Load Obligations and Real-Time Adjusted Load Obligations and for the designation of FTRs.

Hub Price is calculated in accordance with Section III.2.8 of Market Rule 1.

HQ Interconnection Capability Credit (HQICC) is a monthly value reflective of the annual installed capacity benefits of the Phase I/II HVDC-TF, as determined by the ISO, using a standard methodology on file with the Commission, in conjunction with the setting of the Installed Capacity Requirement. An appropriate share of the HQICC shall be assigned to an IRH if the Phase I/II HVDC-TF support costs are paid by that IRH and such costs are not included in the calculation of the Regional Network Service rate. The share of HQICC allocated to such an eligible IRH for a month is the sum in kilowatts of (1)(a) the IRH's percentage share, if any, of the Phase I Transfer Capability times (b) the Phase I Transfer Credit, plus (2)(a) the IRH's percentage share, if any, of the Phase II Transfer Capability, times (b) the Phase II Transfer Credit. The ISO shall establish appropriate HQICCs to apply for an IRH which has such a percentage share.

Import Capacity Resource means an Existing Import Capacity Resource or a New Import Capacity Resource offered to provide capacity in the New England Control Area from an external Control Area.

Inadvertent Energy Revenue is defined in Section III.3.2.1(o) of Market Rule 1.

Inadvertent Energy Revenue Charges or Credits is defined in Section III.3.2.1(p) of Market Rule 1.

Inadvertent Interchange means the difference between net actual energy flow and net scheduled energy flow into or out of the New England Control Area.

Increment Offer means an offer to sell energy at a specified Location in the Day-Ahead Energy Market which is not associated with a physical supply. An accepted Increment Offer results in scheduled supply at the specified Location in the Day-Ahead Energy Market.

Incremental ARR is an ARR provided in recognition of a participant-funded transmission system upgrade pursuant to Appendix C of this Market Rule.

Incremental ARR Holder is an entity which is the record holder of an Incremental Auction Revenue Right in the register maintained by the ISO.

Incremental Cost of Reliability Service is described in Section III.13.2.5.2.5.2 of Market Rule 1.

Independent Transmission Company (ITC) is a transmission entity that assumes certain responsibilities in accordance with Section 10.05 of the Transmission Operating Agreement and Attachment M to the OATT, subject to the acceptance or approval of the Commission and a finding of the Commission that the transmission entity satisfies applicable independence requirements.

Information Request is a request from a potential Disputing Party submitted in writing to the ISO for access to Confidential Information.

Initial Market Participant Financial Assurance Requirement is calculated for new Market Participants and Returning Market Participants, other than an FTR-Only Customer or a Governance Only Member, according to Section IV of the ISO New England Financial Assurance Policy.

Installed Capacity Requirement means the level of capacity required to meet the reliability requirements defined for the New England Control Area, as described in Section III.12 of Market Rule 1.

Interchange Transactions are transactions deemed to be effected under Market Rule 1.

Interconnecting Transmission Owner has the meaning specified in Section I of Schedule 22, Attachment 1 to Schedule 23, and Section I of Schedule 25 of the OATT.

Interconnection Agreement is the “Large Generator Interconnection Agreement”, the “Small Generator Interconnection Agreement”, or the “Elective Transmission Upgrade Interconnection Agreement”

pursuant to Schedules 22, 23 or 25 of the ISO OATT or an interconnection agreement approved by the Commission prior to the adoption of the Interconnection Procedures.

Interconnection Customer has the meaning specified in Section I of Schedule 22, Attachment 1 to Schedule 23, and Section I of Schedule 25 of the OATT.

Interconnection Feasibility Study Agreement has the meaning specified in Section I of Schedule 22, Attachment 1 to Schedule 23, or Section I of Schedule 25 of the OATT.

Interconnection Procedure is the “Large Generator Interconnection Procedures”, the “Small Generator Interconnection Procedures”, or the “Elective Transmission Upgrade Interconnection Procedures” pursuant to Schedules 22, 23, and 25 of the ISO OATT.

Interconnection Reliability Operating Limit (IROL) has the meaning specified in the Glossary of Terms Used in NERC Reliability Standards.

Interconnection Request has the meaning specified in Section I of Schedule 22, Attachment 1 to Schedule 23, or Section I of Schedule 25 of the OATT.

Interconnection Rights Holder(s) (IRH) has the meaning given to it in Schedule 20A to Section II of this Tariff.

Interconnection System Impact Study Agreement has the meaning specified in Section I of Schedule 22, Attachment 1 to Schedule 23 and Section I of Schedule 25 of the OATT.

Interest is interest calculated in the manner specified in Section II.8.3.

Interface Bid is a unified real-time bid to simultaneously purchase and sell energy on each side of an external interface for which the enhanced scheduling procedures in Section III.1.10.7.A are implemented.

Intermittent Power Resource is a wind, solar, run of river hydro or other renewable resource that does not have control over its net power output.

Internal Bilateral for Load is an internal bilateral transaction under which the buyer receives a reduction in Real-Time Load Obligation and the seller receives a corresponding increase in Real-Time Load Obligation in the amount of the sale, in MWs. An Internal Bilateral for Load transaction is only applicable in the Real-Time Energy Market.

Internal Bilateral for Market for Energy is an internal bilateral transaction for Energy which applies in the Day-Ahead Energy Market and Real-Time Energy Market or just the Real-Time Energy Market under which the buyer receives a reduction in Day-Ahead Adjusted Load Obligation and Real-Time Adjusted Load Obligation and the seller receives a corresponding increase in Day-Ahead Adjusted Load Obligation and Real-Time Adjusted Load Obligation in the amount of the sale, in MWs.

Internal Elective Transmission Upgrade (Internal ETU) is defined in Section I of Schedule 25 of the OATT.

Internal Market Monitor means the department of the ISO responsible for carrying out the market monitoring and mitigation functions specified in Appendix A and elsewhere in Market Rule 1.

Interregional Planning Stakeholder Advisory Committee (IPSAC) is the committee described as such in the Northeast Planning Protocol.

Interregional Transmission Project is a transmission project located within the New England Control Area and one or more of the neighboring transmission planning regions.

Interruption Cost is the amount, in dollars, that must be paid to a Market Participant each time the Market Participant's Demand Response Resource is scheduled or dispatched in the New England Markets to reduce demand.

Inventoried Energy Day is an Operating Day that occurs in the months of December, January, or February during the winters of 2023-2024 ~~and 2024-2025~~ (inventoried energy program) and for which the average of the high temperature and the low temperature on that Operating Day, as measured and reported by the National Weather Service at Bradley International Airport in Windsor Locks, Connecticut, is less than or equal to 17 degrees Fahrenheit, as described in Section III.K.3.1 of Market Rule 1.

Investment Grade Rating, for a Market (other than an FTR-Only Customer) or Non-Market Participant Transmission Customer, is either (a) a corporate investment grade rating from one or more of the Rating Agencies, or (b) if the Market Participant or Non-Market Participant Transmission Customer does not have a corporate rating from one of the Rating Agencies, then an investment grade rating for the Market Participant's or Non-Market Participant Transmission Customer's senior unsecured debt from one or more of the Rating Agencies.

Invoice is a statement issued by the ISO for the net Charge owed by a Covered Entity pursuant to the ISO New England Billing Policy.

Invoice Date is the day on which the ISO issues an Invoice.

ISO means ISO New England Inc.

ISO Charges, for the purposes of the ISO New England Billing Policy, are both Non-Hourly Charges and Hourly Charges.

ISO Control Center is the primary control center established by the ISO for the exercise of its Operating Authority and the performance of functions as an RTO.

ISO-Initiated Claimed Capability Audit is the audit performed pursuant to Section III.1.5.1.4.

ISO New England Administrative Procedures means procedures adopted by the ISO to fulfill its responsibilities to apply and implement ISO New England System Rules.

ISO New England Billing Policy is Exhibit ID to Section I of the Transmission, Markets and Services Tariff.

ISO New England Filed Documents means the Transmission, Markets and Services Tariff, including but not limited to Market Rule 1, the Participants Agreement, the Transmission Operating Agreement or other documents that affect the rates, terms and conditions of service.

ISO New England Financial Assurance Policy is Exhibit IA to Section I of the Transmission, Markets and Services Tariff.

ISO New England Information Policy is the policy establishing guidelines regarding the information received, created and distributed by Market Participants and the ISO in connection with the settlement, operation and planning of the System, as the same may be amended from time to time in accordance with the provisions of this Tariff. The ISO New England Information Policy is Attachment D to the Transmission, Markets and Services Tariff.

ISO New England Manuals are the manuals implementing Market Rule 1, as amended from time to time in accordance with the Participants Agreement. Any elements of the ISO New England Manuals that substantially affect rates, terms, and/or conditions of service shall be filed with the Commission under Section 205 of the Federal Power Act.

ISO New England Operating Documents are the Tariff and the ISO New England Operating Procedures.

ISO New England Operating Procedures (OPs) are the ISO New England Planning Procedures and the operating guides, manuals, procedures and protocols developed and utilized by the ISO for operating the ISO bulk power system and the New England Markets.

ISO New England Planning Procedures are the procedures developed and utilized by the ISO for planning the ISO bulk power system.

ISO New England System Rules are Market Rule 1, the ISO New England Information Policy, the ISO New England Administrative Procedures, the ISO New England Manuals and any other system rules, procedures or criteria for the operation of the New England Transmission System and administration of the New England Markets and the Transmission, Markets and Services Tariff.

ITC Agreement is defined in Attachment M to the OATT.

ITC Rate Schedule is defined in Section 3.1 of Attachment M to the OATT.

ITC System is defined in Section 2.2 of Attachment M to the OATT.

ITC System Planning Procedures is defined in Section 15.4 of Attachment M to the OATT.

Joint ISO/RTO Planning Committee (JIPC) is the committee described as such in the Northeastern Planning Protocol.

Late Payment Account is a segregated interest-bearing account into which the ISO deposits Late Payment Charges due from ISO Charges and interest owed from participants for late payments that are collected and not distributed to the Covered Entities, until the Late Payment Account Limit is reached, under the ISO New England Billing Policy and penalties collected under the ISO New England Financial Assurance Policy.

Late Payment Account Limit is defined in Section 4.2 of the ISO New England Billing Policy.

Late Payment Charge is defined in Section 4.1 of the ISO New England Billing Policy.

Lead Market Participant, for purposes other than the Forward Capacity Market, is the entity authorized to submit Supply Offers, Demand Bids or Demand Reduction Offers for a Resource and to whom certain Energy TUs are assessed under Schedule 2 of Section IV.A of the Tariff. For purposes of the Forward Capacity Market, the Lead Market Participant is the entity designated to participate in that market on behalf of an Existing Capacity Resource or a New Capacity Resource.

Limited Energy Resource means a Generator Asset that, due to design considerations, environmental restriction on operations, cyclical requirements, such as the need to recharge or refill or manage water flow, or fuel limitations, are unable to operate continuously at full output on a daily basis.

Load Asset means a physical load that has been registered in accordance with the Asset Registration Process. A Load Asset can be an Asset Related Demand, including a Dispatchable Asset Related Demand.

Load Management means measures (e.g., products, equipment, systems, services, practices and/or strategies) on end-use customer facilities that curtail electrical usage or shift electrical usage while delivering a comparable or acceptable level of end-use service. Such measures include, but are not limited to, energy management systems, load control end-use cycling, load curtailment strategies, and energy storage that curtails or shifts electrical usage by means other than generating electricity.

Load Shedding is the systematic reduction of system demand by temporarily decreasing load.

Load Zone is a Reliability Region, except as otherwise provided for in Section III.2.7 of Market Rule 1.

Local Area Facilities are defined in the TOA**.**

Local Benefit Upgrade(s) (LBU) is an upgrade, modification or addition to the transmission system that is: (i) rated below 115kV or (ii) rated 115kV or above and does not meet all of the non-voltage criteria for PTF classification specified in the OATT.

Local Control Centers are those control centers in existence as of the effective date of the OATT (including the CONVEX, REMVEC, Maine and New Hampshire control centers) or established by the PTOs in accordance with the TOA that are separate from the ISO Control Center and perform certain functions in accordance with the OATT and the TOA.

Local Delivery Service is the service of delivering electric energy to end users. This service is subject to state jurisdiction regardless of whether such service is provided over local distribution or transmission facilities. An entity that is an Eligible Customer under the OATT is not excused from any requirements of state law, or any order or regulation issued pursuant to state law, to arrange for Local Delivery Service with the Participating Transmission Owner and/or distribution company providing such service and to pay all applicable charges associated with such service, including charges for stranded costs and benefits.

Local Network is defined as the transmission facilities constituting a local network as identified in Attachment E, as such Attachment may be modified from time to time in accordance with the Transmission Operating Agreement.

Local Network Load is the load that a Network Customer designates for Local Network Service under Schedule 21 to the OATT.

Local Network RNS Rate is the rate applicable to Regional Network Service to effect a delivery to load in a particular Local Network, as determined in accordance with Schedule 9 to the OATT.

Local Network Service (LNS) is the network service provided under Schedule 21 and the Local Service Schedules to permit the Transmission Customer to efficiently and economically utilize its resources to serve its load.

Local Point-To-Point Service (LPTP) is Point-to-Point Service provided under Schedule 21 of the OATT and the Local Service Schedules to permit deliveries to or from an interconnection point on the PTF.

Local Public Policy Transmission Upgrade is any addition and/or upgrade to the New England Transmission System with a voltage level below 115kV that is required in connection with the construction of a Public Policy Transmission Upgrade approved for inclusion in the Regional System Plan pursuant to Attachment K to the ISO OATT or included in a Local System Plan in accordance with Appendix 1 to Attachment K.

Local Resource Adequacy Requirement is calculated pursuant to Section III.12.2.1.1.

Local Second Contingency Protection Resources are those Resources identified by the ISO on a daily basis as necessary for the provision of Operating Reserve requirements and adherence to NERC, NPCC and ISO reliability criteria over and above those Resources required to meet first contingency reliability criteria within a Reliability Region.

Local Service is transmission service provided under Schedule 21 and the Local Service Schedules thereto.

Local Service Schedule is a PTO-specific schedule to the OATT setting forth the rates, charges, terms and conditions applicable to Local Service.

Local Sourcing Requirement (LSR) is a value calculated as described in Section III.12.2.1 of Market Rule 1.

Local System Planning (LSP) is the process defined in Appendix 1 of Attachment K to the OATT.

Localized Costs are costs that the ISO, with advisory input from the Reliability Committee, determines in accordance with Schedule 12C of the OATT shall not be included in the Pool-Supported PTF costs

recoverable under this OATT, or in costs allocated to Regional Network Load according to Section 6 of Schedule 12. If there are any Localized Costs, the ISO shall identify them in the Regional System Plan.

Location is a Node, External Node, Load Zone, DRR Aggregation Zone, or Hub.

Locational Marginal Price (LMP) is defined in Section III.2 of Market Rule 1. The Locational Marginal Price for a Node is the nodal price at that Node; the Locational Marginal Price for an External Node is the nodal price at that External Node; the Locational Marginal Price for a Load Zone, DRR Aggregation Zone or Reliability Region is the Zonal Price for that Load Zone, DRR Aggregation Zone or Reliability Region, respectively; and the Locational Marginal Price for a Hub is the Hub Price for that Hub.

Long Lead Time Facility (Long Lead Facility) has the meaning specified in Section I of Schedule 22 and Schedule 25 of the OATT.

Long-Term is a term of one year or more.

Long-Term Transmission Outage is a long-term transmission outage scheduled in accordance with ISO New England Operating Procedure No. 3.

Loss Component is the component of the nodal LMP at a given Node or External Node on the PTF that reflects the cost of losses at that Node or External Node relative to the reference point. The Loss Component of the nodal LMP at a given Node on the non-PTF system reflects the relative cost of losses at that Node adjusted as required to account for losses on the non-PTF system already accounted for through tariffs associated with the non-PTF. When used in connection with Hub Price or Zonal Price, the term Loss Component refers to the Loss Components of the nodal LMPs that comprise the Hub Price or Zonal Price, which Loss Components are averaged or weighted in the same way that nodal LMPs are averaged to determine Hub Price or weighted to determine Zonal Price.

Loss of Load Expectation (LOLE) is the probability of disconnecting non-interruptible customers due to a resource deficiency.

Lost Opportunity Cost (LOC) is one of four forms of compensation that may be paid to resources providing VAR Service under Schedule 2 of the OATT.

LSE means load serving entity.

Lump Sum Blackstart Payment is defined and calculated as specified in Section 5.4 of Schedule 16 to the OATT.

Lump Sum Blackstart Capital Payment is defined and calculated as specified in Section 5.4 of Schedule 16 to the OATT.

Manual Response Rate is the rate, in MW/Minute, at which the output of a Generator Asset, or the consumption of a Dispatchable Asset Related Demand, is capable of changing.

Marginal Loss Revenue Load Obligation is defined in Section III.3.2.1(b) of Market Rule 1.

Marginal Reliability Impact is the change, with respect to an increment of capacity supply, in expected unserved energy due to resource deficiency, as measured in hours per year.

Market Credit Limit is a credit limit for a Market Participant's Financial Assurance Obligations (except FTR Financial Assurance Requirements) established for each Market Participant in accordance with Section II.C of the ISO New England Financial Assurance Policy.

Market Credit Test Percentage is calculated in accordance with Section III.B.1(a) of the ISO New England Financial Assurance Policy.

Market Efficiency Transmission Upgrade is defined as those additions and upgrades that are not related to the interconnection of a generator, and, in the ISO's determination, are designed to reduce bulk power system costs to load system-wide, where the net present value of the reduction in bulk power system costs to load system-wide exceeds the net present value of the cost of the transmission addition or upgrade. For purposes of this definition, the term "bulk power system costs to load system-wide" includes, but is not limited to, the costs of energy, capacity, reserves, losses and impacts on bilateral prices for electricity.

Market Participant is a participant in the New England Markets (including a FTR-Only Customer) that has executed a Market Participant Service Agreement, or on whose behalf an unexecuted Market Participant Service Agreement has been filed with the Commission.

Market Participant Financial Assurance Requirement is defined in Section III of the ISO New England Financial Assurance Policy.

Market Participant Obligations is defined in Section III.B.1.1 of Appendix B of Market Rule 1.

Market Participant Service Agreement (MPSA) is an agreement between the ISO and a Market Participant, in the form specified in Attachment A or Attachment A-1 to the Tariff, as applicable.

Market Rule 1 is ISO Market Rule 1 and appendices set forth in Section III of this ISO New England Inc. Transmission, Markets and Services Tariff, as it may be amended from time to time.

Market Violation is a tariff violation, violation of a Commission-approved order, rule or regulation, market manipulation, or inappropriate dispatch that creates substantial concerns regarding unnecessary market inefficiencies.

Material Adverse Change is any change in financial status including, but not limited to a downgrade to below an Investment Grade Rating by any Rating Agency, being placed on credit watch with negative implication by any Rating Agency if the Market Participant or Non-Market Participant Transmission Customer does not have an Investment Grade Rating, a bankruptcy filing or other insolvency, a report of a significant quarterly loss or decline of earnings, the resignation of key officer(s), the sanctioning of the Market Participant or Non-Market Participant Transmission Customer or any of its Principles imposed by the Federal Energy Regulatory Commission, the Securities Exchange Commission, any exchange monitored by the National Futures Association, or any state entity responsible for regulating activity in energy markets; the filing of a material lawsuit that could materially adversely impact current or future financial results; a significant change in the Market Participant's or Non-Market Participant Transmission Customer's credit default spreads; or a significant change in market capitalization.

Material Adverse Impact is defined, for purposes of review of ITC-proposed plans, as a proposed facility or project will be deemed to cause a "material adverse impact" on facilities outside of the ITC System if: (i) the proposed facility or project causes non-ITC facilities to exceed their capabilities or

exceed their thermal, voltage or stability limits, consistent with all applicable reliability criteria, or (ii) the proposed facility or project would not satisfy the standards set forth in Section I.3.9 of the Transmission, Markets and Services Tariff. This standard is intended to assure the continued service of all non-ITC firm load customers and the ability of the non-ITC systems to meet outstanding transmission service obligations.

Maximum Capacity Limit is a value calculated as described in Section III.12.2.2 of Market Rule 1.

Maximum Consumption Limit is the maximum amount, in MW, available for economic dispatch from a DARD and is based on the physical characteristics as submitted as part of the DARD's Offer Data. A Market Participant must maintain an up-to-date Maximum Consumption Limit (and where applicable, must provide the ISO with any telemetry required by ISO New England Operating Procedure No. 18 to allow the ISO to maintain an updated Maximum Consumption Limit) for all hours in which a DARD has been offered into the Day-Ahead Energy Market or Real-Time Energy Market.

Maximum Daily Energy Limit is the maximum amount of megawatt-hours that a Limited Energy Resource expects to be able to generate in the next Operating Day.

Maximum Daily Consumption Limit is the maximum amount of megawatt-hours that a Storage DARD expects to be able to consume in the next Operating Day.

Maximum Facility Load is the highest demand of an end-use customer facility since the start of the prior calendar year (or, if unavailable, an estimate thereof), where the demand evaluated is established by adding metered demand measured at the Retail Delivery Point and the output of all generators located behind the Retail Delivery Point in the same time intervals.

Maximum Interruptible Capacity is an estimate of the maximum demand reduction and Net Supply that a Demand Response Asset can deliver, as measured at the Retail Delivery Point.

Maximum Load is the highest demand since the start of the prior calendar year (or, if unavailable, an estimate thereof), as measured at the Retail Delivery Point.

Maximum Number of Daily Starts is the maximum number of times that a Binary Storage DARD or a Generator Asset can be started or that a Demand Response Resource can be interrupted in the next Operating Day under normal operating conditions.

Maximum Reduction is the maximum available demand reduction, in MW, of a Demand Response Resource that a Market Participant offers to deliver in the Day-Ahead Energy Market or Real-Time Energy Market, as reflected in the Demand Response Resource's Demand Reduction Offer.

Measure Life is the estimated time an On-Peak Demand Resource or Seasonal Peak Demand Resource measure will remain in place, or the estimated time period over which the facility, structure, equipment or system in which a measure is installed continues to exist, whichever is shorter. Suppliers of On-Peak Demand Resources or Seasonal Peak Demand Resources comprised of an aggregation of measures with varied Measures Lives shall determine and document the Measure Life either: (i) for each type of measure with a different Measure Life and adjust the aggregate performance based on the individual measure life calculation in the portfolio; or (ii) as the average Measure Life for the aggregated measures as long as the demand reduction capability of the resource is greater than or equal to the amount that cleared in the Forward Capacity Auction or reconfiguration auction for the entire Capacity Commitment Period, and the demand reduction capability for an Existing On-Peak Demand Resource or Existing Seasonal Peak Demand Resource is not over-stated in a subsequent Capacity Commitment Period. Measure Life shall be determined consistent with the resource's Measurement and Verification Plan, which shall be reviewed by the ISO to ensure consistency with the measurement and verification requirements of Market Rule 1 and the ISO New England Manuals.

Measurement and Verification Documents mean the measurement and verification documents described in Section 13.1.4.3.1 of Market Rule 1 that are submitted by On-Peak Demand Resources and Seasonal Peak Demand Resources, which include Measurement and Verification Plans, Updated Measurement and Verification Plans, Measurement and Verification Summary Reports, and Measurement and Verification Reference Reports.

Measurement and Verification Plan means the measurement and verification plan submitted by an On-Peak Demand Resource or Seasonal Peak Demand Resource as part of the qualification process for the Forward Capacity Auction pursuant to the requirements of Section III.13.1.4.3 of Market Rule 1 and the ISO New England Manuals.

Measurement and Verification Reference Reports are optional reports submitted by On-Peak Demand Resources or Seasonal Peak Demand Resources during the Capacity Commitment Period subject to the schedule in the Measurement and Verification Plan and consistent with the schedule and reporting standards set forth in the ISO New England Manuals. Measurement and Verification Reference Reports update the prospective demand reduction capability of the On-Peak Demand Resource or Seasonal Peak Demand Resource project based on measurement and verification studies performed during the Capacity Commitment Period.

Measurement and Verification Summary Report is the monthly report submitted by an On-Peak Demand Resource or Seasonal Peak Demand Resource with the monthly settlement report for the Forward Capacity Market, which documents the total demand reduction capability for all On-Peak Demand Resources and Seasonal Peak Demand Resources in operation as of the end of the previous month.

MEPCO Grandfathered Transmission Service Agreement (MGTSA) is a MEPCO long-term firm point-to-point transmission service agreement with a POR or POD at the New Brunswick border and a start date prior to June 1, 2007 where the holder has elected, by written notice delivered to MEPCO within five (5) days following the filing of the settlement agreement in Docket Nos. ER07-1289 and EL08-56 or by September 1, 2008 (whichever is later), MGTSA treatment as further described in Section II.45.1.

Merchant Transmission Facilities (MTF) are the transmission facilities owned by MTOs, defined and classified as MTF pursuant to Schedule 18 of the OATT, over which the ISO shall exercise Operating Authority in accordance with the terms set forth in a MTOA or Attachment K to the OATT, rated 69 kV or above and required to allow energy from significant power sources to move freely on the New England Transmission System.

Merchant Transmission Facilities Provider (MTF Provider) is an entity as defined in Schedule 18 of the OATT.

Merchant Transmission Facilities Service (MTF Service) is transmission service over MTF as provided for in Schedule 18 of the OATT.

Merchant Transmission Operating Agreement (MTOA) is an agreement between the ISO and an MTO with respect to its MTF.

Merchant Transmission Owner (MTO) is an owner of MTF.

Meter Data Error means an error in meter data, including an error in Coincident Peak Contribution values, on an Invoice issued by the ISO after the completion of the Data Reconciliation Process as described in the ISO New England Manuals and in Section III.3.8 of Market Rule 1.

Meter Data Error RBA Submission Limit means the date thirty 30 calendar days after the issuance of the Invoice containing the results of the Data Reconciliation Process as described in the ISO New England Manuals and in Section III.3.6 of Market Rule 1.

Metered Quantity For Settlement is defined in Section III.3.2.1.1 of Market Rule 1.

Minimum Consumption Limit is (a) the lowest consumption level, in MW, available for economic dispatch from a DARD and is based on the physical characteristics as submitted as part of the DARD's Offer Data, and (b) for a DARD undergoing Facility and Equipment Testing or auditing, the level to which the DARD requests and is approved to operate or is directed to operate for purposes of completing the Facility and Equipment Testing or auditing.

Minimum Down Time is the number of hours that must elapse after a Generator Asset or Storage DARD has been released for shutdown at or below its Economic Minimum Limit or Minimum Consumption Limit before the Generator Asset or Storage DARD can be brought online and be released for dispatch at its Economic Minimum Limit or Minimum Consumption Limit.

Minimum Generation Emergency means an Emergency declared by the ISO in which the ISO anticipates requesting one or more Generator Assets to operate at or below Economic Minimum Limit in order to manage, alleviate, or end the Emergency.

Minimum Generation Emergency Credits are those Real-Time Dispatch NCPC Credits calculated pursuant to Appendix F of Market Rule 1 for resources within a reliability region that are dispatched during a period for which a Minimum Generation Emergency has been declared.

Minimum Reduction is the minimum available demand reduction, in MW, of a Demand Response Resource that a Market Participant offers to deliver in the Day-Ahead Energy Market or Real-Time Energy Market, as reflected in the Demand Response Resource's Demand Reduction Offer.

Minimum Reduction Time is the minimum number of hours of demand reduction at or above the Minimum Reduction for which the ISO must dispatch a Demand Response Resource to reduce demand.

Minimum Run Time is the number of hours that a Generator Asset must remain online after it has been scheduled to reach its Economic Minimum Limit before it can be released for shutdown from its Economic Minimum Limit or the number of hours that must elapse after a Storage DARD has been scheduled to consume at its Minimum Consumption Limit before it can be released for shutdown.

Minimum Time Between Reductions is the number of hours that must elapse after a Demand Response Resource has received a Dispatch Instruction to stop reducing demand before the Demand Response Resource can achieve its Minimum Reduction after receiving a Dispatch Instruction to start reducing demand.

Minimum Total Reserve Requirement, which does not include Replacement Reserve, is the combined amount of TMSR, TMNSR, and TMOR required system-wide as described in Section III.2.7A and ISO New England Operating Procedure No. 8.

Monthly Blackstart Service Charge is the charge made to Transmission Customers pursuant to Section 6 of Schedule 16 to the OATT.

Monthly Capacity Payment is the Forward Capacity Market payment described in Section III.13.7.3 of Market Rule 1.

Monthly Peak is defined in Section II.21.2 of the OATT.

Monthly PER is calculated in accordance with Section III.13.7.1.2.2 of Market Rule 1.

Monthly Real-Time Demand Reduction Obligation is the absolute value of a Customer's hourly Real-Time Demand Reduction Obligation summed for all hours in a month, in MWhs.

Monthly Real-Time Generation Obligation is the sum, for all hours in a month, at all Locations, of a Customer's Real-Time Generation Obligation, in MWhs.

Monthly Real-Time Load Obligation is the absolute value of a Customer's hourly Real-Time Load Obligation summed for all hours in a month, in MWhs.

Monthly Regional Network Load is defined in Section II.21.2 of the OATT.

Monthly Statement is the first weekly Statement issued on a Monday after the tenth of a calendar month that includes both the Hourly Charges for the relevant billing period and Non-Hourly Charges for the immediately preceding calendar month.

MRI Transition Period is the period specified in Section III.13.2.2.1.

MUI is the market user interface.

Municipal Market Participant is defined in Section II of the ISO New England Financial Assurance Policy.

MW is megawatt.

MWh is megawatt-hour.

Native Load Customers are the wholesale and retail power customers of a Transmission Owner on whose behalf the Transmission Owner, by statute, franchise, regulatory requirement, or contract, has undertaken an obligation to construct and operate its system to meet the reliable electric needs of such customers.

NCPC Charge means the charges to Market Participants calculated pursuant to Appendix F to Market Rule 1.

NCPC Credit means the credits to Market Participants calculated pursuant to Appendix F to Market Rule 1.

Needs Assessment is defined in Section 4.1 of Attachment K to the OATT.

NEMA, for purposes of Section III of the Tariff, is the Northeast Massachusetts Reliability Region.

NEMA Contract is a contract described in Appendix C of Market Rule 1 and listed in Exhibit 1 of Appendix C of Market Rule 1.

NEMA Load Serving Entity (NEMA LSE) is a Transmission Customer or Congestion Paying LSE Entity that serves load within NEMA.

NEMA or Northeast Massachusetts Upgrade, for purposes of Section II of the Tariff, is an addition to or modification of the PTF into or within the Northeast Massachusetts Reliability Region that was not, as of December 31, 1999, the subject of a System Impact Study or application filed pursuant to Section I.3.9 of the Transmission, Markets and Services Tariff; that is not related to generation interconnections; and that will be completed and placed in service by June 30, 2004. Such upgrades include, but are not limited to, new transmission facilities and related equipment and/or modifications to existing transmission facilities and related equipment. The list of NEMA Upgrades is contained in Schedule 12A of the OATT.

NEPOOL is the New England Power Pool, and the entities that collectively participated in the New England Power Pool.

NEPOOL Agreement is the agreement among the participants in NEPOOL.

NEPOOL GIS is the generation information system.

NEPOOL GIS Administrator is the entity or entities that develop, administer, operate and maintain the NEPOOL GIS.

NEPOOL GIS API Fees are the one-time on-boarding fees and annual maintenance fees charged to NEPOOL by the NEPOOL GIS Administrator for each NEPOOL Participant or Market Participant that accesses the NEPOOL GIS through an application programming interface pursuant to Rule 3.9(b) of the operating rules of the NEPOOL GIS.

NEPOOL Participant is a party to the NEPOOL Agreement.

NERC is the North American Electric Reliability Corporation or its successor organization.

NESCOE is the New England States Committee on Electricity, recognized by the Commission as the regional state committee for the New England Control Area.

Net Commitment Period Compensation (NCPC) is the compensation methodology for Resources that is described in Appendix F to Market Rule 1.

Net CONE is an estimate of the Cost of New Entry, net of the first-year non-capacity market revenues, for a reference technology resource type and is intended to equal the amount of capacity revenue the reference technology resource would require, in its first year of operation, to be economically viable given reasonable expectations of the first year energy and ancillary services revenues, and projected revenue for subsequent years.

Net Regional Clearing Price is described in Section III.13.7.5 of Market Rule 1.

Net Supply is energy injected into the transmission or distribution system at a Retail Delivery Point.

Net Supply Capability is the maximum Net Supply a facility is physically and contractually able to inject into the transmission or distribution system at its Retail Delivery Point.

Network Capability Interconnection Standard has the meaning specified in Section I of Schedule 22, Attachment 1 to Schedule 23, and Section I of Schedule 25 of the OATT.

Network Customer is a Transmission Customer receiving RNS or LNS.

Network Import Capability (NI Capability) is defined in Section I of Schedule 25 of the OATT.

Network Import Interconnection Service (NI Interconnection Service) is defined in Section I of Schedule 25 of the OATT.

Network Resource is defined as follows: (1) With respect to Market Participants, (a) any generating resource located in the New England Control Area which has been placed in service prior to the

Compliance Effective Date (including a unit that has lost its capacity value when its capacity value is restored and a deactivated unit which may be reactivated without satisfying the requirements of Section II.46 of the OATT in accordance with the provisions thereof) until retired; (b) any generating resource located in the New England Control Area which is placed in service after the Compliance Effective Date until retired, provided that (i) the Generator Owner has complied with the requirements of Sections II.46 and II.47 and Schedules 22 and 23 of the OATT, and (ii) the output of the unit shall be limited in accordance with Sections II.46 and II.47 and Schedules 22 and 23, if required; and (c) any generating resource or combination of resources (including bilateral purchases) located outside the New England Control Area for so long as any Market Participant has an Ownership Share in the resource or resources which is being delivered to it in the New England Control Area to serve Regional Network Load located in the New England Control Area or other designated Regional Network Loads contemplated by Section II.18.3 of the OATT taking Regional Network Service. (2) With respect to Non-Market Participant Transmission Customers, any generating resource owned, purchased or leased by the Non-Market Participant Transmission Customer which it designates to serve Regional Network Load.

New Brunswick Security Energy is defined in Section III.3.2.6A of Market Rule 1.

New Capacity Offer is an offer in the Forward Capacity Auction to provide capacity from a New Generating Capacity Resource, New Import Capacity Resource or New Demand Capacity Resource.

New Capacity Qualification Deadline is a deadline, specified in Section III.13.1.10 of Market Rule 1, for submission of certain qualification materials for the Forward Capacity Auction, as discussed in Section III.13.1 of Market Rule 1.

New Capacity Qualification Package is information submitted by certain new resources prior to participation in the Forward Capacity Auction, as described in Section III.13.1 of Market Rule 1.

New Capacity Resource is a resource (i) that never previously received any payment as a capacity resource including any capacity payment pursuant to the market rules in effect prior to June 1, 2010 and that has not cleared in any previous Forward Capacity Auction; or (ii) that is otherwise eligible to participate in the Forward Capacity Auction as a New Capacity Resource.

New Capacity Show of Interest Form is described in Section III.13.1.1.2.1 of Market Rule 1.

New Capacity Show of Interest Submission Window is the period of time during which a Project Sponsor may submit a New Capacity Show of Interest Form or a New Demand Capacity Resource Show of Interest Form, as described in Section III.13.1.10 of Market Rule 1.

New Demand Capacity Resource is a type of Demand Capacity Resource participating in the Forward Capacity Market, as defined in Section III.13.1.4.1 of Market Rule 1.

New Demand Capacity Resource Qualification Package is the information that a Project Sponsor must submit, in accordance with Section III.13.1.4.1.1.2 of Market Rule 1, for each resource that it seeks to offer in the Forward Capacity Auction as a New Demand Capacity Resource.

New Demand Capacity Resource Show of Interest Form is described in Section III.13.1.4.1.1.1 of Market Rule 1.

New England Control Area is the Control Area for New England, which includes PTF, Non-PTF, MTF and OTF. The New England Control Area covers Connecticut, Rhode Island, Massachusetts, New Hampshire, Vermont, and part of Maine (i.e., excluding the portions of Northern Maine and the northern portion of Eastern Maine which are in the Maritimes Control Area).

New England Markets are markets or programs for the purchase of energy, capacity, ancillary services, demand response services or other related products or services (including Financial Transmission Rights) that are delivered through or useful to the operation of the New England Transmission System and that are administered by the ISO pursuant to rules, rates, or agreements on file from time to time with the Federal Energy Regulatory Commission.

New England System Restoration Plan is the plan that is developed by ISO, in accordance with NERC Reliability Standards, NPCC regional criteria and standards, ISO New England Operating Documents and ISO operating agreements, to facilitate the restoration of the New England Transmission System following a partial or complete shutdown of the New England Transmission System.

New England Transmission System is the system of transmission facilities, including PTF, Non-PTF, OTF and MTF, within the New England Control Area under the ISO's operational jurisdiction.

New Generating Capacity Resource is a type of resource participating in the Forward Capacity Market, as described in Section III.13.1.1.1 of Market Rule 1.

New Import Capacity Resource is a type of resource participating in the Forward Capacity Market, as defined in Section III.13.1.3.4 of Market Rule 1.

New Resource Offer Floor Price is defined in Section III.A.21.2.

NMPTC means Non-Market Participant Transmission Customer.

NMPTC Credit Threshold is described in Section V.A.2 of the ISO New England Financial Assurance Policy.

NMPTC Financial Assurance Requirement is an amount of additional financial assurance for Non-Market Participant Transmission Customers described in Section V.D of the ISO New England Financial Assurance Policy.

Node is a point on the New England Transmission System at which LMPs are calculated.

No-Load Fee is the amount, in dollars per hour, for a Generator Asset that must be paid to Market Participants with an Ownership Share in the Generator Asset for being scheduled in the New England Markets, in addition to the Start-Up Fee and price offered to supply energy, for each hour that the Generator Asset is scheduled in the New England Markets.

Nominated Consumption Limit is the consumption level specified by the Market Participant for a Dispatchable Asset Related Demand as adjusted in accordance with the provisions of Section III.13.7.5.1.3.

Non-Commercial Capacity is the capacity of a New Capacity Resource or an Existing Capacity Resource, or portion thereof, that has not achieved FCM Commercial Operation.

Non-Commercial Capacity Cure Period is the time period described in Section VII.D of the ISO New England Financial Assurance Policy.

Non-Commercial Capacity Financial Assurance Amount (Non-Commercial Capacity FA Amount) is the financial assurance amount held on Non-Commercial Capacity cleared in a Forward Capacity Auction as calculated in accordance with Section VII.B.2 of the ISO New England Financial Assurance Policy.

Non-Designated Blackstart Resource Study Cost Payments are the study costs reimbursed under Section 5.3 of Schedule 16 of the OATT.

Non-Dispatchable Resource is any Resource that does not meet the requirements to be a Dispatchable Resource.

Non-Hourly Charges are defined in Section 1.3 of the ISO New England Billing Policy.

Non-Hourly Requirements are determined in accordance with Section III.A(ii) of the ISO New England Financial Assurance Policy, which is Exhibit 1A of Section I of the Tariff.

Non-Incumbent Transmission Developer is a Qualified Transmission Project Sponsor that: (i) is not currently a PTO; (ii) has a transmission project listed in the RSP Project List; and (iii) has executed a Non-Incumbent Transmission Developer Operating Agreement. "Non-Incumbent Transmission Developer" also includes a PTO that proposes the development of a transmission facility not located within or connected to its existing electric system; however, because such a PTO is a party to the TOA, it is not required to enter into a Non-Incumbent Transmission Developer Operating Agreement.

Non-Incumbent Transmission Developer Operating Agreement (or NTDOA) is an agreement between the ISO and a Non-Incumbent Transmission Developer in the form specified in Attachment O to the OATT that sets forth their respective rights and responsibilities to each other with regard to proposals for and construction of certain transmission facilities.

Non-Market Participant is any entity that is not a Market Participant.

Non-Market Participant Transmission Customer is any entity which is not a Market Participant but is a Transmission Customer.

Non-Municipal Market Participant is defined in Section II of the ISO New England Financial Assurance Policy.

Non-PTF Transmission Facilities (Non-PTF) are the transmission facilities owned by the PTOs that do not constitute PTF, OTF or MTF.

Non-Qualifying means a Market Participant that is not a Credit Qualifying Market Participant.

Notice of RBA is defined in Section 6.3.2 of the ISO New England Billing Policy.

Notification Time is the time required for a Generator Asset to synchronize to the system from the time a startup Dispatch Instruction is received from the ISO.

Northeastern Planning Protocol is the Amended and Restated Northeastern ISO/RTO Planning Coordination Protocol on file with the Commission and posted on the ISO website at the following URL: www.iso-ne.com/static-assets/documents/2015/07/northeastern_protocol_dmeast.doc.

NPCC is the Northeast Power Coordinating Council.

Obligation Month means a time period of one calendar month for which capacity payments are issued and the costs associated with capacity payments are allocated.

Offer Data means the scheduling, operations planning, dispatch, new Resource, and other data, including Generator Asset, Dispatchable Asset Related Demand, and Demand Response Resource operating limits based on physical characteristics, and information necessary to schedule and dispatch Generator Assets, Dispatchable Asset Related Demands, and Demand Response Resources for the provision or consumption of energy, the provision of other services, and the maintenance of the reliability and security of the transmission system in the New England Control Area, and specified for submission to the New England Markets for such purposes by the ISO.

Offered CLAIM10 is a Supply Offer value or a Demand Reduction Offer value between 0 and the CLAIM10 of the resource that represents the amount of TMNSR available either from an off-line Fast Start Generator or from a Fast Start Demand Response Resource that has not been dispatched.

Offered CLAIM30 is a Supply Offer value or a Demand Reduction Offer value between 0 and the CLAIM30 of the resource that represents the amount of TMOR available either from an off-line Fast Start Generator or from a Fast Start Demand Response Resource that has not been dispatched.

On-Peak Demand Resource is a type of Demand Capacity Resource and means installed measures (e.g., products, equipment, systems, services, practices and/or strategies) on end-use customer facilities that reduce the total amount of electrical energy consumed during Demand Resource On-Peak Hours, while delivering a comparable or acceptable level of end-use service. Such measures include Energy Efficiency, Load Management, and Distributed Generation.

Open Access Same-Time Information System (OASIS) is the ISO information system and standards of conduct responding to requirements of 18 C.F.R. §37 of the Commission's regulations and all additional requirements implemented by subsequent Commission orders dealing with OASIS.

Open Access Transmission Tariff (OATT) is Section II of the ISO New England Inc. Transmission, Markets and Services Tariff.

Operating Authority is defined pursuant to a MTOA, an OTOA, the TOA or the OATT, as applicable.

Operating Data means GADS Data, data equivalent to GADS Data, CARL Data, metered load data, or actual system failure occurrences data, all as described in the ISO New England Operating Procedures.

Operating Day means the calendar day period beginning at midnight for which transactions on the New England Markets are scheduled.

Operating Reserve means Ten-Minute Spinning Reserve (TMSR), Ten-Minute Non-Spinning Reserve (TMNSR) and Thirty-Minute Operating Reserve (TMOR).

Operations Date is February 1, 2005.

OTF Service is transmission service over OTF as provided for in Schedule 20.

Other Transmission Facility (OTF) are the transmission facilities owned by Transmission Owners, defined and classified as OTF pursuant to Schedule 20, over which the ISO shall exercise Operating

Authority in accordance with the terms set forth in the OTOA, rated 69 kV or above, and required to allow energy from significant power sources to move freely on the New England Transmission System. OTF classification shall be limited to the Phase I/II HVDC-TF.

Other Transmission Operating Agreements (OTOA) is the agreement(s) between the ISO, an OTO and/or the associated service provider(s) with respect to an OTF, which includes the HVDC Transmission Operating Agreement and the Phase I/II HVDC-TF Transmission Service Administration Agreement. With respect to the Phase I/II HVDC-TF, the HVDC Transmission Operating Agreement covers the rights and responsibilities for the operation of the facility and the Phase I/II HVDC-TF Transmission Service Administration Agreement covers the rights and responsibilities for the administration of transmission service.

Other Transmission Owner (OTO) is an owner of OTF.

Ownership Share is a right or obligation, for purposes of settlement, to a percentage share of all credits or charges associated with a Generator Asset or a Load Asset, where such facility is interconnected to the New England Transmission System.

Participant Expenses are defined in Section 1 of the Participants Agreement.

Participant Required Balance is defined in Section 5.3 of the ISO New England Billing Policy.

Participant Vote is defined in Section 1 of the Participants Agreement.

Participants Agreement is the agreement among the ISO, the New England Power Pool and Individual Participants, as amended from time to time, on file with the Commission.

Participants Committee is the principal committee referred to in the Participants Agreement.

Participating Transmission Owner (PTO) is a transmission owner that is a party to the TOA.

Passive DR Audit is the audit performed pursuant to Section III.13.6.1.5.4.

Passive DR Auditing Period is the summer Passive DR Auditing Period (June 1 to August 31) or winter Passive DR Auditing Period (December 1 to January 31) applicable to On-Peak Demand Resources and Seasonal Peak Demand Resources.

Payment is a sum of money due to a Covered Entity from the ISO.

Payment Default Shortfall Fund is defined in Section 5.1 of the ISO New England Billing Policy.

Peak Energy Rent (PER) is described in Section III.13.7.1.2 of Market Rule 1.

PER Proxy Unit is described in Section III.13.7.1.2.1 of Market Rule 1.

Permanent De-list Bid is a bid that may be submitted by an Existing Generating Capacity Resource, Existing Import Capacity Resource, or Existing Demand Capacity Resource in the Forward Capacity Auction to permanently remove itself from the capacity market, as described in Section III.13.1.2.3.1.5 of Market Rule 1.

Phase I Transfer Credit is 40% of the HQICC, or such other fraction of the HQICC as the ISO may establish.

Phase I/II HVDC-TF is defined in Schedule 20A to Section II of this Tariff.

Phase I/II HVDC-TF Transfer Capability is the transfer capacity of the Phase I/II HVDC-TF under normal operating conditions, as determined in accordance with Good Utility Practice. The “Phase I Transfer Capability” is the transfer capacity under normal operating conditions, as determined in accordance with Good Utility Practice, of the Phase I terminal facilities as determined initially as of the time immediately prior to Phase II of the Phase I/II HVDC-TF first being placed in service, and as adjusted thereafter only to take into account changes in the transfer capacity which are independent of any effect of Phase II on the operation of Phase I. The “Phase II Transfer Capability” is the difference between the Phase I/II HVDC-TF Transfer Capability and the Phase I Transfer Capability. Determinations of, and any adjustment in, Phase I/II HVDC-TF Transfer Capability shall be made by the ISO, and the basis for any such adjustment shall be explained in writing and posted on the ISO website.

Phase One Proposal is a first round submission, as defined in Section 4.3 of Attachment K of the OATT, of a proposal for a Reliability Transmission Upgrade or Market Efficiency Transmission Upgrade, as applicable, by a Qualified Transmission Project Sponsor.

Phase II Transfer Credit is 60% of the HQICC, or such other fraction of the HQICC as the ISO may establish.

Phase Two Solution is a second round submission, as defined in Section 4.3 of Attachment K of the OATT, of a proposal for a Reliability Transmission Upgrade or Market Efficiency Transmission Upgrade by a Qualified Transmission Project Sponsor.

Planning Advisory Committee is the committee described in Attachment K of the OATT.

Planning and Reliability Criteria is defined in Section 3.3 of Attachment K to the OATT.

Planning Authority is an entity defined as such by the North American Electric Reliability Corporation.

Point(s) of Delivery (POD) is point(s) of interconnection where capacity and/or energy transmitted by a Transmission Customer will be made available to the Receiving Party under the OATT.

Point of Interconnection shall have the same meaning as that used for purposes of Schedules 22, 23 and 25 of the OATT.

Point(s) of Receipt (POR) is point(s) of interconnection where capacity and/or energy transmitted by a Transmission Customer will be made available by the Delivering Party under the OATT.

Point-To-Point Service is the transmission of capacity and/or energy on either a firm or non-firm basis from the Point(s) of Receipt to the Point(s) of Delivery under the OATT pursuant to Local Point-To-Point Service or OTF Service or MTF Service; and the transmission of capacity and/or energy from the Point(s) of Receipt to the Point(s) of Delivery under the OATT pursuant to Through or Out Service.

Pool-Planned Unit is one of the following units: New Haven Harbor Unit 1 (Coke Works), Mystic Unit 7, Canal Unit 2, Potter Unit 2, Wyman Unit 4, Stony Brook Units 1, 1A, 1B, 1C, 2A and 2B, Millstone

Unit 3, Seabrook Unit 1 and Waters River Unit 2 (to the extent of 7 megawatts of its Summer capability and 12 megawatts of its Winter capability).

Pool PTF Rate is the transmission rate determined in accordance with Schedule 8 to the OATT.

Pool RNS Rate is the transmission rate determined in accordance with paragraph (2) of Schedule 9 of Section II of the Tariff.

Pool-Scheduled Resources are described in Section III.1.10.2 of Market Rule 1.

Pool Supported PTF is defined as: (i) PTF first placed in service prior to January 1, 2000; (ii) Generator Interconnection Related Upgrades with respect to Category A and B projects (as defined in Schedule 11), but only to the extent not paid for by the interconnecting Generator Owner; and (iii) other PTF upgrades, but only to the extent the costs therefore are determined to be Pool Supported PTF in accordance with Schedule 12.

Pool Transmission Facility (PTF) means the transmission facilities owned by PTOs which meet the criteria specified in Section II.49 of the OATT.

Posting Entity is any Market Participant or Non-Market Participant Transmission Customer providing financial security under the provisions of the ISO New England Financial Assurance Policy.

Posture means an action of the ISO to deviate from the jointly optimized security constrained economic dispatch for Energy and Operating Reserves solution for a Resource produced by the ISO’s technical software for the purpose of maintaining sufficient Operating Reserve (both online and off-line) or for the provision of voltage or VAR support.

Posturing Credits are the Real-Time Posturing NCPC Credits for Generators (Other Than Limited Energy Resources) Postured for Reliability and the Real-Time Posturing NCPC Credit for Limited Energy Resources Postured for Reliability.

Power Purchaser is the entity that is purchasing the capacity and/or energy to be transmitted under the OATT.

Principal is (i) the sole proprietor of a sole proprietorship; (ii) a general partner of a partnership; (iii) a president, chief executive officer, chief operating officer or chief financial officer (or equivalent position) of an organization; (iv) a manager, managing member or a member vested with the management authority for a limited liability company or limited liability partnership; (v) any person or entity that has the power to exercise a controlling influence over an organization's activities that are subject to regulation by the Federal Energy Regulatory Commission, the Securities and Exchange Commission, the Commodity Futures Trading Commission, any exchange monitored by the National Futures Association, or any state entity responsible for regulating activity in energy markets; or (vi) any person or entity that: (a) is the direct owner of 10% or more of any class of an organization's equity securities; or (b) has directly contributed 10% or more of an organization's capital.

Profiled Load Assets include all Load Assets that are not directly metered by OP-18 compliant metering as currently described in Section IV (Metering and Recording for Settlements) of OP18, and some Load Assets that are measured by OP-18 compliant metering (as currently described in Section IV of OP-18) to which the Host Participant Assigned Meter Reader allocates non-PTF losses.

Project Sponsor is an entity seeking to have a New Generating Capacity Resource, New Import Capacity Resource or New Demand Capacity Resource participate in the Forward Capacity Market, as described in Section III.13.

Proxy De-List Bid is a type of bid used in the Forward Capacity Market.

Provisional Member is defined in Section I.68A of the Restated NEPOOL Agreement.

PTO Administrative Committee is the committee referred to in Section 11.04 of the TOA.

Public Policy Requirement is a requirement reflected in a statute enacted by, or a regulation promulgated by, the federal government or a state or local (e.g., municipal or county) government.

Public Policy Transmission Study is a study conducted by the ISO pursuant to the process set out in Section 4A.3 of Attachment K of the OATT, and consists of two phases: (i) an initial phase to produce a rough estimate of the costs and benefits of concepts that could meet transmission needs driven by public policy requirements; and (ii) a follow-on phase designed to produce more detailed analysis and engineering work on transmission concepts identified in the first phase.

Public Policy Local Transmission Study is a study conducted by a PTO pursuant to the process set out in Section 1.6 of Attachment K Appendix 1 of the OATT, and consists of two phases: (i) an initial phase to produce an estimate of the costs and benefits of concepts that could meet transmission needs driven by public policy requirements; and (ii) a follow-on phase designed to produce more detailed analysis and engineering work on transmission concepts identified in the first phase.

Public Policy Transmission Upgrade is an addition and/or upgrade to the New England Transmission System that meets the voltage and non-voltage criteria for Public Policy Transmission Upgrade PTF classification specified in the OATT, and has been included in the Regional System Plan and RSP Project List as a Public Policy Transmission Upgrade pursuant to the procedures described in Section 4A of Attachment K of the OATT.

Publicly Owned Entity is defined in Section I of the Restated NEPOOL Agreement.

Qualification Process Cost Reimbursement Deposit is described in Section III.13.1.9.3 of Market Rule 1.

Qualified Capacity is the amount of capacity a resource may provide in the summer or winter in a Capacity Commitment Period, as determined in the Forward Capacity Market qualification processes.

Qualified Generator Reactive Resource(s) is any generator source of dynamic reactive power that meets the criteria specified in Schedule 2 of the OATT.

Qualified Non-Generator Reactive Resource(s) is any non-generator source of dynamic reactive power that meets the criteria specified in Schedule 2 of the OATT.

Qualified Reactive Resource(s) is any Qualified Generator Reactive Resource and/or Qualified Non-Generator Reactive Resource that meets the criteria specified in Schedule 2 of the OATT.

Qualified Transmission Project Sponsor is defined in Sections 4B.2 and 4B.3 of Attachment K of the OATT.

Queue Position has the meaning specified in Section I of Schedule 22, Attachment 1 to Schedule 23, and Section I of Schedule 25 of the OATT.

Rapid Response Pricing Asset is: (i) a Fast Start Generator; (ii) a Flexible DNE Dispatchable Generator; or (iii) a Binary Storage DARD with Offer Data specifying a Minimum Run Time and a Minimum Down Time not exceeding one hour each. A Rapid Response Pricing Asset shall also include a Fast Start Demand Response Resource for which the Market Participant's Offer Data meets the following criteria: (i) Minimum Reduction Time does not exceed one hour; and (ii) Demand Response Resource Notification Time plus Demand Response Resource Start-Up Time does not exceed 30 minutes.

Rapid Response Pricing Opportunity Cost is the NCPC Credit described in Section III.F.2.3.10.

Rated means a Market Participant that receives a credit rating from one or more of the Rating Agencies, or, if such Market Participant is not rated by one of the Rating Agencies, then a Market Participant that has outstanding unsecured debt rated by one or more of the Rating Agencies.

Rating Agencies are Standard and Poor's (S&P), Moody's, and Fitch.

Rationing Minimum Limit is the MW quantity for a New Generating Capacity Resource or Existing Generating Capacity Resource below which n offer or bid may not be rationed in the Forward Capacity Auction, but shall not apply to supply offers or demand bids in a substitution auction as specified in Section III.13.2.8.2 and Section III.13.2.8.3.

RBA Decision is a written decision provided by the ISO to a Disputing Party and to the Chair of the NEPOOL Budget and Finance Subcommittee accepting or denying a Requested Billing Adjustment within twenty Business Days of the date the ISO distributes a Notice of RBA, unless some later date is agreed upon by the Disputing Party and the ISO.

Reactive Capability Audit is an audit that measures the ability of a Reactive Resource to provide or absorb reactive power to or from the transmission system at a specified real power output or consumption.

Reactive Resource is a device that dynamically adjusts reactive power output automatically in Real-Time over a continuous range, taking into account control system response bandwidth, within a specified voltage bandwidth in response to grid voltage changes. These resources operate to maintain a set-point

voltage and include, but are not limited to, Generator Assets, Dispatchable Asset Related Demands that are part of an Electric Storage Facility, and dynamic transmission devices.

Reactive Supply and Voltage Control Service is the form of Ancillary Service described in Schedule 2 of the OATT.

Real-Time is a period in the current Operating Day for which the ISO dispatches Resources for energy and Regulation, designates Resources for Regulation and Operating Reserve and, if necessary, commits additional Resources.

Real-Time Adjusted Load Obligation is defined in Section III.3.2.1(b) of Market Rule 1.

Real-Time Adjusted Load Obligation Deviation is defined in Section III.3.2.1(d) of Market Rule 1.

Real-Time Commitment NCPC Credit is an NCPC Credit calculated pursuant to Appendix F to Market Rule 1.

Real-Time Congestion Revenue is defined in Section III.3.2.1(i) of Market Rule 1.

Real-Time Demand Reduction Obligation is defined in Section III.3.2.1(c) of Market Rule 1.

Real-Time Demand Reduction Obligation Deviation is defined in Section III.3.2.1(e) of Market Rule 1.

Real-Time Dispatch NCPC Credit is an NCPC Credit calculated pursuant to Appendix F to Market Rule 1.

Real-Time Energy Inventory is a component of the spot payment that a Market Participant may receive through the inventoried energy program, as described in Section III.K.3.2.1 of Market Rule 1.

Real-Time Energy Market means the purchase or sale of energy, purchase of demand reductions, payment of Congestion Costs, and payment for losses for quantity deviations from the Day-Ahead Energy Market in the Operating Day and designation of and payment for provision of Operating Reserve in Real-Time.

Real-Time Energy Market Deviation Congestion Charge/Credit is defined in Section III.3.2.1(g) of Market Rule 1.

Real-Time Energy Market Deviation Energy Charge/Credit is defined in Section III.3.2.1(g) of Market Rule 1.

Real-Time Energy Market Deviation Loss Charge/Credit is defined in Section III.3.2.1(g) of Market Rule 1.

Real-Time Energy Market NCPC Credits are the Real-Time Commitment NCPC Credit and the Real-Time Dispatch NCPC Credit.

Real-Time External Transaction NCPC Credit is an NCPC Credit calculated pursuant to Appendix F to Market Rule 1.

Real-Time Generation Obligation is defined in Section III.3.2.1(b) of Market Rule 1.

Real-Time Generation Obligation Deviation is defined in Section III.3.2.1(d) of Market Rule 1.

Real-Time High Operating Limit is the maximum output, in MW, of a Generator Asset that could be achieved, consistent with Good Utility Practice, in response to an ISO request for Energy (including pursuant to Section III.13.6.4 of Market Rule 1), for each hour of the Operating Day, as reflected in the Generator Asset's Offer Data. This value is based on real-time operating conditions and the physical operating characteristics and operating permits of the facility and must be submitted for all Generator Assets (other than Settlement Only Resources).

Real-Time Load Obligation is defined in Section III.3.2.1(b) of Market Rule 1.

Real-Time Load Obligation Deviation is defined in Section III.3.2.1(d) of Market Rule 1.

Real-Time Locational Adjusted Net Interchange is defined in Section III.3.2.1(b) of Market Rule 1.

Real-Time Locational Adjusted Net Interchange Deviation is defined in Section III.3.2.1(d) of Market Rule 1.

Real-Time Loss Revenue is defined in Section III.3.2.1(l) of Market Rule 1.

Real-Time Loss Revenue Charges or Credits are defined in Section III.3.2.1(m) of Market Rule 1.

Real-Time NCP Load Obligation is the maximum hourly value, during a month, of a Market Participant's Real-Time Load Obligation summed over all Locations, excluding exports, in kilowatts.

Real-Time Offer Change is a modification to a Supply Offer pursuant to Section III.1.10.9(b).

Real-Time Posturing NCPC Credit for Generators (Other Than Limited Energy Resources) Postured for Reliability is an NCPC Credit calculated pursuant to Appendix F to Market Rule 1.

Real-Time Posturing NCPC Credit for Limited Energy Resources Postured for Reliability is an NCPC Credit calculated pursuant to Appendix F to Market Rule 1.

Real-Time Prices means the Locational Marginal Prices resulting from the ISO's dispatch of the New England Markets in the Operating Day.

Real-Time Reserve Charge is a Market Participant's share of applicable system and Reserve Zone Real-Time Operating Reserve costs attributable to meeting the Real-Time Operating Reserve requirement as calculated in accordance with Section III.10 of Market Rule 1.

Real-Time Reserve Clearing Price is the Real-Time TMSR, TMNSR or TMOR clearing price, as applicable, for the system and each Reserve Zone that is calculated in accordance with Section III.2.7A of Market Rule 1.

Real-Time Reserve Credit is a Market Participant's compensation associated with that Market Participant's Resources' Reserve Quantity For Settlement as calculated in accordance with Section III.10 of Market Rule 1.

Real-Time Reserve Designation is the amount, in MW, of Operating Reserve designated to a Resource in Real-Time by the ISO as described in Section III.1.7.19 of Market Rule 1.

Real-Time Reserve Opportunity Cost is defined in Section III.2.7A(b) of Market Rule 1.

Real-Time Synchronous Condensing NCPC Credit is an NCPC Credit calculated pursuant to Appendix F to Market Rule 1.

Real-Time System Adjusted Net Interchange means, for each hour, the sum of Real-Time Locational Adjusted Net Interchange for a Market Participant over all Locations, in kilowatts.

Receiving Party is the entity receiving the capacity and/or energy transmitted to Point(s) of Delivery under the OATT.

Reference Level is defined in Section III.A.5.7 of Appendix A of Market Rule 1.

Regional Benefit Upgrade(s) (RBU) means a Transmission Upgrade that: (i) is rated 115kV or above; (ii) meets all of the non-voltage criteria for PTF classification specified in the OATT; and (iii) is included in the Regional System Plan as either a Reliability Transmission Upgrade or a Market Efficiency Transmission Upgrade identified as needed pursuant to Attachment K of the OATT. The category of RBU shall not include any Transmission Upgrade that has been categorized under any of the other categories specified in Schedule 12 of the OATT (e.g., an Elective Transmission Upgrade shall not also be categorized as an RBU). Any upgrades to transmission facilities rated below 115kV that were PTF prior to January 1, 2004 shall remain classified as PTF and be categorized as an RBU if, and for so long as, such upgrades meet the criteria for PTF specified in the OATT.

Regional Network Load is the load that a Network Customer designates for Regional Network Service under Part II.B of the OATT. The Network Customer's Regional Network Load shall include all load designated by the Network Customer (including losses) and shall not be credited or reduced for any behind-the-meter generation. A Network Customer may elect to designate less than its total load as Regional Network Load but may not designate only part of the load at a discrete Point of Delivery. Where a Transmission Customer has elected not to designate a particular load at discrete Points of Delivery as Regional Network Load, the Transmission Customer is responsible for making separate arrangements

under Part II.C of the OATT for any Point-To-Point Service that may be necessary for such non-designated load.

Regional Network Service (RNS) is the transmission service over the PTF described in Part II.B of the OATT, including such service which is used with respect to Network Resources or Regional Network Load that is not physically interconnected with the PTF.

Regional Planning Dispute Resolution Process is described in Section 12 of Attachment K to the OATT.

Regional System Plan (RSP) is the plan developed under the process specified in Attachment K of the OATT.

Regional Transmission Service (RTS) is Regional Network Service and Through or Out Service as provided over the PTF in accordance with Section II.B, Section II.C, Schedule 8 and Schedule 9 of the OATT.

Regulation is the capability of a specific Resource with appropriate telecommunications, control and response capability to respond to an AGC SetPoint.

Regulation and Frequency Response Service is the form of Ancillary Service described in Schedule 3 of the OATT. The capability of performing Regulation and Frequency Response Service is referred to as automatic generation control (AGC).

Regulation Capacity is the lesser of five times the Automatic Response Rate and one-half of the difference between the Regulation High Limit and the Regulation Low Limit of a Resource capable of providing Regulation.

Regulation Capacity Requirement is the amount of Regulation Capacity required to maintain system control and reliability in the New England Control Area as calculated and posted on the ISO website.

Regulation Capacity Offer is an offer by a Market Participant to provide Regulation Capacity.

Regulation High Limit is an offer parameter that establishes the upper bound for AGC SetPoints and is used in the determination of a Resource's Regulation Capacity.

Regulation Low Limit is an offer parameter that establishes the lower bound for AGC SetPoints and is used in the determination of a Resource's Regulation Capacity.

Regulation Market is the market described in Section III.14 of Market Rule 1.

Regulation Resources are those Alternative Technology Regulation Resources and Generator Assets that satisfy the requirements of Section III.14.2. Regulation Resources are eligible to participate in the Regulation Market.

Regulation Service is the change in output or consumption made in response to changing AGC SetPoints.

Regulation Service Requirement is the estimated amount of Regulation Service required to maintain system control and reliability in the New England Control Area as calculated and posted on the ISO website.

Regulation Service Offer is an offer by a Market Participant to provide Regulation Service.

Related Person is defined pursuant to Section 1.1 of the Participants Agreement.

Related Transaction is defined in Section III.1.4.3 of Market Rule 1.

Reliability Administration Service (RAS) is the service provided by the ISO, as described in Schedule 3 of Section IV.A of the Tariff, in order to administer the Reliability Markets and provide other reliability-related and informational functions.

Reliability Committee is the committee whose responsibilities are specified in Section 8.2.3 of the Participants Agreement.

Reliability Markets are, collectively, the ISO's administration of Regulation, the Forward Capacity Market, and Operating Reserve.

Reliability Region means any one of the regions identified on the ISO's website. Reliability Regions are intended to reflect the operating characteristics of, and the major transmission constraints on, the New England Transmission System.

Reliability Transmission Upgrade means those additions and upgrades not required by the interconnection of a generator that are nonetheless necessary to ensure the continued reliability of the New England Transmission System, taking into account load growth and known resource changes, and include those upgrades necessary to provide acceptable stability response, short circuit capability and system voltage levels, and those facilities required to provide adequate thermal capability and local voltage levels that cannot otherwise be achieved with reasonable assumptions for certain amounts of generation being unavailable (due to maintenance or forced outages) for purposes of long-term planning studies. Good Utility Practice, applicable reliability principles, guidelines, criteria, rules, procedures and standards of ERO and NPCC and any of their successors, applicable publicly available local reliability criteria, and the ISO System Rules, as they may be amended from time to time, will be used to define the system facilities required to maintain reliability in evaluating proposed Reliability Transmission Upgrades. A Reliability Transmission Upgrade may provide market efficiency benefits as well as reliability benefits to the New England Transmission System.

Remittance Advice is an issuance from the ISO for the net Payment owed to a Covered Entity where a Covered Entity's total Payments exceed its total Charges in a billing period.

Remittance Advice Date is the day on which the ISO issues a Remittance Advice.

Renewable Technology Resource is a Generating Capacity Resource or an On-Peak Demand Resource that satisfies the requirements specified in Section III.13.1.1.1.7.

Re-Offer Period is the period that normally occurs between the posting of the of the Day-Ahead Energy Market results and 2:00 p.m. on the day before the Operating Day during which a Market Participant may submit revised Supply Offers, revised External Transactions, or revised Demand Bids associated with Dispatchable Asset Related Demands or, revised Demand Reduction Offers associated with Demand Response Resources.

Replacement Reserve is described in Part III, Section VII of ISO New England Operating Procedure No. 8.

Request for Alternative Proposals (RFAP) is the request described in Attachment K of the OATT.

Requested Billing Adjustment (RBA) is defined in Section 6.1 of the ISO New England Billing Policy.

Required Balance is an amount as defined in Section 5.3 of the Billing Policy.

Reseller is a MGTSA holder that sells, assigns or transfers its rights under its MGTSA, as described in Section II.45.1(a) of the OATT.

Reserve Adequacy Analysis is the analysis performed by the ISO to determine if adequate Resources are committed to meet forecasted load, Operating Reserve, and security constraint requirements for the current and next Operating Day.

Reserve Constraint Penalty Factors (RCPFs) are rates, in $/MWh, that are used within the Real-Time dispatch and pricing algorithm to reflect the value of Operating Reserve shortages and are defined in Section III.2.7A(c) of Market Rule 1; and, commencing on June 1, 2024, that are used within the Day-Ahead Energy Market security-constrained economic commitment and dispatch process to reflect the value of Day-Ahead Ancillary Services shortages and forecast energy requirement shortages and are defined in Section III.2.6.2(b) of Market Rule 1.

Reserve Quantity For Settlement is defined in Section III.10.1 of Market Rule 1.

Reserve Zone is defined in Section III.2.7 of Market Rule 1.

Reserved Capacity is the maximum amount of capacity and energy that is committed to the Transmission Customer for transmission over the New England Transmission System between the Point(s) of Receipt and the Point(s) of Delivery under Part II.C or Schedule 18, 20 or 21 of the OATT, as applicable. Reserved Capacity shall be expressed in terms of whole kilowatts on a sixty-minute interval (commencing on the clock hour) basis, or, in the case of Reserved Capacity for Local Point-to-Point Service, in terms of whole megawatts on a sixty-minute interval basis.

Resource means a Generator Asset, a Dispatchable Asset Related Demand, an External Resource, an External Transaction, or a Demand Response Resource.

Restated New England Power Pool Agreement (RNA) is the Second Restated New England Power Pool Agreement, which restated for a second time by an amendment dated as of August 16, 2004 the New England Power Pool Agreement dated September 1, 1971, as the same may be amended and restated from time to time, governing the relationship among the NEPOOL members.

Rest-of-Pool Capacity Zone is a single Capacity Zone made up of the adjacent Load Zones that are neither export-constrained nor import-constrained.

Rest of System is an area established under Section III.2.7(d) of Market Rule 1.

Retail Delivery Point is the point on the transmission or distribution system at which the load of an end-use facility, which is metered and assigned a unique account number by the Host Participant, is measured to determine the amount of energy delivered to the facility from the transmission and distribution system. If an end-use facility is connected to the transmission or distribution system at more than one location, the Retail Delivery Point shall consist of the metered load at each connection point, summed to measure the net energy delivered to the facility in each interval.

Retirement De-List Bid is a bid to retire an Existing Generating Capacity Resource, Existing Import Capacity Resource, or Existing Demand Capacity Resource from all New England Markets, as described in Section III.13.1.2.3.1.5.

Returning Market Participant is a Market Participant, other than an FTR-Only Customer or a Governance Only Member, whose previous membership as a Market Participant was involuntarily terminated due to a Financial Assurance Default or a payment default and, since returning, has been a Market Participant for less than six consecutive months.

Revenue Requirement is defined in Section IV.A.2.1 of the Tariff.

Reviewable Action is defined in Section III.D.1.1 of Appendix D of Market Rule 1.

Reviewable Determination is defined in Section 12.4(a) of Attachment K to the OATT.

RSP Project List is defined in Section 1 of Attachment K to the OATT.

RTEP02 Upgrade(s) means a Transmission Upgrade that was included in the annual NEPOOL Transmission Plan (also known as the "Regional Transmission Expansion Plan" or "RTEP") for the year 2002, as approved by ISO New England Inc.'s Board of Directors, or the functional equivalent of such Transmission Upgrade, as determined by ISO New England Inc. The RTEP02 Upgrades are listed in Schedule 12B of the OATT.

RTO is a regional transmission organization or comparable independent transmission organization that complies with Order No. 2000 and the Commission's corresponding regulation.

Same Reserve Zone Export Transaction is defined in Section III.1.10.7(f)(iii) of Market Rule 1.

Sanctionable Behavior is defined in Section III.B.3 of Appendix B of Market Rule 1.

Schedule, Schedules, Schedule 1, 2, 3, 4 and 5 are references to the individual or collective schedules to Section IV.A. of the Tariff.

Schedule 20A Service Provider (SSP) is defined in Schedule 20A to Section II of this Tariff.

Scheduling Service, for purposes of Section IV.A and Section IV.B of the Tariff, is the service described in Schedule 1 to Section IV.A of the Tariff.

Scheduling, System Control and Dispatch Service, for purposes of Section II of the Tariff, is the form of Ancillary Service described in Schedule 1 of the OATT.

Seasonal Claimed Capability is the summer or winter claimed capability of a Generator Asset or Generating Capacity Resource, and represents the maximum dependable load carrying ability of the asset or resource, excluding capacity required for station use.

Seasonal Claimed Capability Audit is the Generator Asset audit performed pursuant to Section III.1.5.1.3.

Seasonal DR Audit is the Demand Response Resource audit performed pursuant to Section III.1.5.1.3.1.

Seasonal Peak Demand Resource is a type of Demand Capacity Resource and shall mean installed measures (e.g., products, equipment, systems, services, practices and/or strategies) on end-use customer facilities that reduce the total amount of electrical energy consumed during Demand Resource Seasonal Peak Hours, while delivering a comparable or acceptable level of end-use service. Such measures include Energy Efficiency, Load Management, and Distributed Generation.

Section III.1.4 Transactions are defined in Section III.1.4.2 of Market Rule 1.

Section III.1.4 Conforming Transactions are defined in Section III.1.4.2 of Market Rule 1.

Security Agreement is Attachment 1 to the ISO New England Financial Assurance Policy.

Selected Qualified Transmission Project Sponsor is the Qualified Transmission Project Sponsor that proposed the Phase Two or Stage Two Solution that has been identified by the ISO as the preferred Phase Two or Stage Two Solution.

Selected Qualified Transmission Project Sponsor Agreement is the agreement between the ISO and a Selected Qualified Transmission Project Sponsor. The Selected Qualified Transmission Project Sponsor Agreement is provided in Attachment P to the OATT.

Self-Schedule is the action of a Market Participant in committing its Generator Asset or DARD, in accordance with applicable ISO New England Manuals, to provide service in an hour, whether or not in the absence of that action the Generator Asset or DARD would have been committed by the ISO to provide the service. For a Generator Asset, Self-Schedule is the action of a Market Participant in committing a Generator Asset to provide Energy in an hour at its Economic Minimum Limit, whether or not in the absence of that action the Generator Asset would have been committed by the ISO to provide the Energy. For a DARD, Self-Schedule is the action of a Market Participant in committing a DARD to consume Energy in an hour at its Minimum Consumption Limit, whether or not in the absence of that action the DARD would have been committed by the ISO to consume Energy. For an External Transaction, a Self-Schedule is a request by a Market Participant for the ISO to select the External Transaction regardless of the LMP. Demand Response Resources are not permitted to Self-Schedule.

Self-Supplied FCA Resource is described in Section III.13.1.6 of Market Rule 1.

Senior Officer means an officer of the subject entity with the title of vice president (or similar office) or higher, or another officer designated in writing to the ISO by that office.

Service Agreement is a Transmission Service Agreement or an MPSA.

Service Commencement Date is the date service is to begin pursuant to the terms of an executed Service Agreement, or the date service begins in accordance with the sections of the OATT addressing the filing of unexecuted Service Agreements.

Services means, collectively, the Scheduling Service, EAS and RAS; individually, a Service.

Settlement Financial Assurance is an amount of financial assurance required from a Designated FTR Participant awarded a bid in an FTR Auction. This amount is calculated pursuant to Section VI.C of the ISO New England Financial Assurance Policy.

Settlement Only Resources are generators of less than 5 MW or otherwise eligible for Settlement Only Resource treatment as described in ISO New England Operating Procedure No. 14 and that have elected Settlement Only Resource treatment as described in the ISO New England Manual for Registration and Performance Auditing.

Shortfall Funding Arrangement, as specified in Section 5.1 of the ISO New England Billing Policy, is a separate financing arrangement that can be used to make up any non-congestion related differences between amounts received on Invoices and amounts due for ISO Charges in any bill issued.

Short-Term is a period of less than one year.

Significantly Reduced Congestion Costs are defined in Section III.G.2.2 of Appendix G to Market Rule 1.

SMD Effective Date is March 1, 2003.

Solutions Study is described in Section 4.2(b) of Attachment K to the OATT.

Special Constraint Resource (SCR) is a Resource that provides Special Constraint Resource Service under Schedule 19 of the OATT.

Special Constraint Resource Service is the form of Ancillary Service described in Schedule 19 of the OATT.

Specified-Term Blackstart Capital Payment is the annual compensation level, as calculated pursuant to Section 5.1 of Schedule 16 of the OATT, for a Designated Blackstart Resource's capital Blackstart Equipment costs associated with the provision of Blackstart Service (except for capital costs associated with adhering to NERC Critical Infrastructure Protection Reliability Standards as part of Blackstart Service).

Sponsored Policy Resource is a New Capacity Resource that: receives an out-of-market revenue source supported by a government-regulated rate, charge or other regulated cost recovery mechanism, and; qualifies as a renewable, clean or alternative energy resource under a renewable energy portfolio standard, clean energy standard, alternative energy portfolio standard, renewable energy goal, or clean energy goal enacted (either by statute or regulation) in the New England state from which the resource receives the out-of-market revenue source and that is in effect on January 1, 2018.

Stage One Proposal is a first round submission, as defined in Sections 4A.5 of Attachment K of the OATT, of a proposal for a Public Policy Transmission Upgrade by a Qualified Transmission Project Sponsor.

Stage Two Solution is a second round submission, as defined in Section 4A.5 of Attachment K of the OATT, of a proposal for a Public Policy Transmission Upgrade by a Qualified Transmission Project Sponsor.

Standard Blackstart Capital Payment is the annual compensation level, as calculated pursuant to Section 5.1 of Schedule 16 of the OATT, for a Designated Blackstart Resource's capital Blackstart Equipment costs associated with the provision of Blackstart Service (except for capital costs associated with adhering to NERC Critical Infrastructure Protection Reliability Standards as part of Blackstart Service).

Start-of-Round Price is the highest price associated with a round of a Forward Capacity Auction as described in Section III.13.2.3.1 of Market Rule 1.

Start-Up Fee is the amount, in dollars, that must be paid for a Generator Asset to Market Participants with an Ownership Share in the Generator Asset each time the Generator Asset is scheduled in the New England Markets to start-up.

Start-Up Time is the time it takes the Generator Asset, after synchronizing to the system, to reach its Economic Minimum Limit and, for dispatchable Generator Assets, be ready for further dispatch by the ISO.

State Estimator means the computer model of power flows specified in Section III.2.3 of Market Rule 1.

Statements, for the purpose of the ISO New England Billing Policy, refer to both Invoices and Remittance Advices.

Static De-List Bid is a bid that may be submitted by an Existing Generating Capacity Resource, Existing Import Capacity Resource, or Existing Demand Capacity Resource in the Forward Capacity Auction to remove itself from the capacity market for a one year period, as described in Section III.13.1.2.3.1.1 of Market Rule 1.

Station is one or more Existing Generating Capacity Resources consisting of one or more assets located within a common property boundary.

Station Going Forward Common Costs are the net costs associated with a Station that are avoided only by the clearing of the Static De-List Bids, the Permanent De-List Bids or the Retirement De-List Bids of all the Existing Generating Capacity Resources comprising the Station.

Station-level Blackstart O&M Payment is defined and calculated as specified in Section 5.1.2 of Schedule 16 to the OATT.

Station-level Specified-Term Blackstart Capital Payment is defined and calculated as specified in Section 5.1.2 of Schedule 16 to the OATT.

Station-level Standard Blackstart Capital Payment is defined and calculated as specified in Section 5.1.2 of Schedule 16 to the OATT.

Storage DARD is a DARD that participates in the New England Markets as part of an Electric Storage Facility, as described in Section III.1.10.6 of Market Rule 1.

Summer ARA Qualified Capacity is described in Section III.13.4.2.1.2.1.1.1 of Market Rule 1.

Summer Capability Period means one of two time periods defined by the ISO for the purposes of rating and auditing resources pursuant to Section III.9. The time period associated with the Summer Capability Period is the period of June 1 through September 30.

Summer Intermittent Reliability Hours are defined in Section III.13.1.2.2.2.1(c) of Market Rule 1.

Supply Offer is a proposal to furnish energy at a Node or Regulation from a Resource that meets the applicable requirements set forth in the ISO New England Manuals submitted to the ISO by a Market Participant with authority to submit a Supply Offer for the Resource. The Supply Offer will be submitted pursuant to Market Rule 1 and applicable ISO New England Manuals, and include a price and information with respect to the quantity proposed to be furnished, technical parameters for the Resource, timing and other matters. A Supply Offer is a subset of the information required in a Market Participant's Offer Data.

Supply Offer Block-Hours are Block-Hours assigned to the Lead Market Participant for each Supply Offer. Blocks of the Supply Offer in effect for each hour will be totaled to determine the quantity of Supply Offer Block-Hours for a given day. In the case that a Resource has a Real-Time unit status of "unavailable" for the entire day, that day will not contribute to the quantity of Supply Offer Block-Hours. However, if the Resource has at least one hour of the day with a unit status of "available," the entire day will contribute to the quantity of Supply Offer Block-Hours.

Synchronous Condenser is a generator that is synchronized to the grid but supplying no energy for the purpose of providing Operating Reserve or VAR or voltage support.

System Condition is a specified condition on the New England Transmission System or on a neighboring system, such as a constrained transmission element or flowgate, that may trigger Curtailment of Long-

Term Firm MTF or OTF Service on the MTF or the OTF using the curtailment priority pursuant to Section II.44 of the Tariff or Curtailment of Local Long-Term Firm Point-to-Point Transmission Service on the non-PTF using the curtailment priority pursuant to Schedule 21 of the Tariff. Such conditions must be identified in the Transmission Customer's Service Agreement.

System Impact Study is an assessment pursuant to Part II.B, II.C, II.G, Schedule 21, Schedule 22, Schedule 23, or Schedule 25 of the OATT of (i) the adequacy of the PTF or Non-PTF to accommodate a request for the interconnection of a new or materially changed generating unit or a new or materially changed interconnection to another Control Area or new Regional Network Service or new Local Service or an Elective Transmission Upgrade, and (ii) whether any additional costs may be required to be incurred in order to provide the interconnection or transmission service.

System Operator shall mean ISO New England Inc. or a successor organization.

System Operating Limit (SOL) has the meaning specified in the Glossary of Terms Used in NERC Reliability Standards.

System-Wide Capacity Demand Curve is the demand curve used in the Forward Capacity Market as specified in Section III.13.2.2.

TADO is the total amount due and owing (not including any amounts due under Section 14.1 of the RNA) at such time to the ISO, NEPOOL, the PTOs, the Market Participants and the Non-Market Participant Transmission Customers, by all PTOs, Market Participants and Non-Market Participant Transmission Customers.

Tangible Net Worth is the value, determined in accordance with international accounting standards or generally accepted accounting principles in the United States, of all of that entity's assets less the following: (i) assets the ISO reasonably believes to be restricted or potentially unavailable to settle a claim in the event of a default (e.g., regulatory assets, restricted assets, and Affiliate assets), net of any matching liabilities, to the extent that the result of that netting is a positive value; (ii) derivative assets, net of any matching liabilities, to the extent that the result of that netting is a positive value; (iii) the amount at which the liabilities of the entity would be shown on a balance sheet in accordance with international accounting standards or generally accepted accounting principles in the United States; (iv) preferred stock: (v) non-controlling interest; and (vi) all of that entity's intangible assets (e.g., patents, trademarks,

franchises, intellectual property, goodwill and any other assets not having a physical existence), in each case as shown on the most recent financial statements provided by such entity to the ISO.

Technical Committee is defined in Section 8.2 of the Participants Agreement.

Ten-Minute Non-Spinning Reserve (TMNSR) is a form of ten-minute reserve capability, determined pursuant to Section III.1.7.19.2.

Ten-Minute Non-Spinning Reserve Service is the form of Ancillary Service described in Schedule 6 of the OATT.

Ten-Minute Reserve Requirement is the combined amount of TMSR and TMNSR required system-wide as described in Section III.2.7A and ISO New England Operating Procedure No. 8.

Ten-Minute Spinning Reserve (TMSR) is a form of ten-minute reserve capability, determined pursuant to Section III.1.7.19.2.

Ten-Minute Spinning Reserve Requirement is the amount of TMSR required system-wide as described in Section III.2.7A and ISO New England Operating Procedure No. 8.

Ten-Minute Spinning Reserve Service is the form of Ancillary Service described in Schedule 5 of the OATT.

Third-Party Sale is any sale for resale in interstate commerce to a Power Purchaser that is not designated as part of Regional Network Load or Local Network Load under the Regional Network Service or Local Network Service, as applicable.

Thirty-Minute Operating Reserve (TMOR) is a form of thirty-minute reserve capability, determined pursuant to Section III.1.7.19.2.

Thirty-Minute Operating Reserve Service is the form of Ancillary Service described in Schedule 7 of the OATT.

Through or Out Rate (TOUT Rate) is the rate per hour for Through or Out Service, as defined in Section II.25.2 of the OATT.

Through or Out Service (TOUT Service) means Point-To-Point Service over the PTF provided by the ISO with respect to a transaction that goes through the New England Control Area, as, for example, a single transaction where energy or capacity is transmitted into the New England Control Area from New Brunswick and subsequently out of the New England Control Area to New York, or a single transaction where energy or capacity is transmitted into the New England Control Area from New York through one point on the PTF and subsequently flows over the PTF prior to passing out of the New England Control Area to New York, or with respect to a transaction which originates at a point on the PTF and flows over the PTF prior to passing out of the New England Control Area, as, for example, from Boston to New York.

Tie-Line Asset is a physical transmission tie-line, or an inter-state or intra-state border arrangement created according to the ISO New England Manuals and registered in accordance with the Asset Registration Process.

Total Available Amount is the sum of the available amount of the Shortfall Funding Arrangement and the balance in the Payment Default Shortfall Fund.

Total Blackstart Capital Payment is the annual compensation calculated under either Section 5.1 or Section 5.2 of Schedule 16 of the OATT, as applicable.

Total Blackstart Service Payments is monthly compensation to Blackstart Owners or Market Participants, as applicable, and as calculated pursuant to Section 5.6 of Schedule 16 to the OATT.

Total Reserve Requirement, which includes Replacement Reserve, is the combined amount of TMSR, TMNSR, and TMOR required system-wide as described in Section III.2.7A and ISO New England Operating Procedure No. 8.

Total System Capacity is the aggregate capacity supply curve for the New England Control Area as determined in accordance with Section III.13.2.3.3 of Market Rule 1.

Transaction Unit (TU) is a type of billing determinant under Schedule 2 of Section IV.A of the Tariff used to assess charges to Customers.

Transition Period: The six-year period commencing on March 1, 1997.

Transmission Charges, for the purposes of the ISO New England Financial Assurance Policy and the ISO New England Billing Policy, are all charges and payments under Schedules 1, 8 and 9 of the OATT.

Transmission Congestion Credit means the allocated share of total Transmission Congestion Revenue credited to each holder of Financial Transmission Rights, calculated and allocated as specified in Section III.5.2 of Market Rule 1.

Transmission Congestion Revenue is defined in Section III.5.2.5(a) of Market Rule 1.

Transmission Constraint Penalty Factors are described in Section III.1.7.5 of Market Rule 1.

Transmission Credit Limit is a credit limit, not to be used to meet FTR Requirements, established for each Market Participant in accordance with Section II.D and each Non-Market Participant Transmission Customer in accordance with Section V.B.2 of the ISO New England Financial Assurance Policy.

Transmission Credit Test Percentage is calculated in accordance with Section III.B.1(c) of the ISO New England Financial Assurance Policy.

Transmission Customer is any Eligible Customer that (i) executes, on its own behalf or through its Designated Agent, an MPSA or TSA, or (ii) requests in writing, on its own behalf or through its Designated Agent, that the ISO, the Transmission Owner, or the Schedule 20A Service Provider, as applicable, file with the Commission, a proposed unexecuted MPSA or TSA containing terms and conditions deemed appropriate by the ISO (in consultation with the applicable PTO, OTO or Schedule 20A Service Provider) in order that the Eligible Customer may receive transmission service under Section II of this Tariff. A Transmission Customer under Section II of this Tariff includes a Market Participant or a Non-Market Participant taking Regional Network Service, Through or Out Service, MTF Service, OTF Service, Ancillary Services, or Local Service.

Transmission Default Amount is all or any part of any amount of Transmission Charges due to be paid by any Covered Entity that the ISO, in its reasonable opinion, believes will not or has not been paid when due.

Transmission Default Period is defined in Section 3.4.f of the ISO New England Billing Policy.

Transmission Late Payment Account is defined in Section 4.2 of the ISO New England Billing Policy.

Transmission Late Payment Account Limit is defined in Section 4.2 of the ISO New England Billing Policy.

Transmission Late Payment Charge is defined in Section 4.1 of the ISO New England Billing Policy.

Transmission, Markets and Services Tariff (Tariff) is the ISO New England Inc. Transmission, Markets and Services Tariff, as amended from time to time.

Transmission Obligations are determined in accordance with Section III.A(vi) of the ISO New England Financial Assurance Policy.

Transmission Operating Agreement (TOA) is the Transmission Operating Agreement between and among the ISO and the PTOs, as amended and restated from time to time.

Transmission Owner means a PTO, MTO or OTO.

Transmission Provider is the ISO for Regional Network Service and Through or Out Service as provided under Section II.B and II.C of the OATT; Cross-Sound Cable, LLC for Merchant Transmission Service as provided under Schedule 18 of the OATT; the Schedule 20A Service Providers for Phase I/II HVDC-TF Service as provided under Schedule 20A of the OATT; and the Participating Transmission Owners for Local Service as provided under Schedule 21 of the OATT.

Transmission Requirements are determined in accordance with Section III.A(iii) of the ISO New England Financial Assurance Policy.

Transmission Security Analysis Requirement shall be determined pursuant to Section III.12.2.1.2.

Transmission Service Agreement (TSA) is the initial agreement and any amendments or supplements thereto: (A) in the form specified in either Attachment A or B to the OATT, entered into by the Transmission Customer and the ISO for Regional Network Service or Through or Out Service; (B) entered into by the Transmission Customer with the ISO and PTO in the form specified in Attachment A to Schedule 21 of the OATT; (C) entered into by the Transmission Customer with an OTO or Schedule 20A Service Provider in the appropriate form specified under Schedule 20 of the OATT; or (D) entered into by the Transmission Customer with a MTO in the appropriate form specified under Schedule 18 of the OATT. A Transmission Service Agreement shall be required for Local Service, MTF Service and OTF Service, and shall be required for Regional Network Service and Through or Out Service if the Transmission Customer has not executed a MPSA.

Transmission Upgrade(s) means an upgrade, modification or addition to the PTF that becomes subject to the terms and conditions of the OATT governing rates and service on the PTF on or after January 1, 2004. This categorization and cost allocation of Transmission Upgrades shall be as provided for in Schedule 12 of the OATT.

UDS is unit dispatch system software.

Unconstrained Export Transaction is defined in Section III.1.10.7(f)(iv) of Market Rule 1.

Uncovered Default Amount is defined in Section 3.3(i) of the ISO New England Billing Policy.

Uncovered Transmission Default Amounts are defined in Section 3.4.f of the ISO New England Billing Policy.

Unrated means a Market Participant that is not a Rated Market Participant.

Unsecured Covered Entity is, collectively, an Unsecured Municipal Market Participant and an Unsecured Non-Municipal Covered Entity.

Unsecured Municipal Default Amount is defined in Section 3.3(i) of the ISO New England Billing Policy.

Unsecured Municipal Market Participant is defined in Section 3.3(h) of the ISO New England Billing Policy.

Unsecured Municipal Transmission Default Amount is defined in Section 3.4.f of the ISO New England Billing Policy.

Unsecured Non-Municipal Covered Entity is a Covered Entity that is not a Municipal Market Participant or a Non-Market Participant Transmission Customer and has a Market Credit Limit or Transmission Credit Limit of greater than $0 under the ISO New England Financial Assurance Policy.

Unsecured Non-Municipal Default Amount is defined in Section 3.3(i) of the ISO New England Billing Policy.

Unsecured Non-Municipal Transmission Default Amount is defined in Section 3.3(i) of the ISO New England Billing Policy.

Unsecured Transmission Default Amounts are, collectively, the Unsecured Municipal Transmission Default Amount and the Unsecured Non-Municipal Transmission Default Amount.

Unsettled FTR Financial Assurance is an amount of financial assurance required from a Designated FTR Participant as calculated pursuant to Section VI.B of the ISO New England Financial Assurance Policy.

Updated Measurement and Verification Plan is an optional Measurement and Verification Plan that may be submitted as part of a subsequent qualification process for a Forward Capacity Auction prior to the beginning of the Capacity Commitment Period of the On-Peak Demand Resource or Seasonal Peak Demand Response project. The Updated Measurement and Verification Plan may include updated project specifications, measurement and verification protocols, and performance data as described in Section III.13.1.4.3.1.2 of Market Rule 1 and the ISO New England Manuals.

VAR CC Rate is the CC rate paid to Qualified Reactive Resources for VAR Service capability under Section IV.A of Schedule 2 of the OATT.

VAR Payment is the payment made to Qualified Reactive Resources for VAR Service capability under Section IV.A of Schedule 2 of the OATT.

VAR Service is the provision of reactive power voltage support to the New England Transmission System by a Qualified Reactive Resource or by other generators that are dispatched by the ISO to provide dynamic reactive power as described in Schedule 2 of the OATT.

Virtual Cap is $2,000/MWh.

Virtual Requirements are determined in accordance with Section III.A(iv) of the ISO New England Financial Assurance Policy.

Volt Ampere Reactive (VAR) is a measurement of reactive power.

Volumetric Measure (VM) is a type of billing determinant under Schedule 2 of Section IV.A of the Tariff used to assess charges to Customers under Section IV.A of the Tariff.

Winter ARA Qualified Capacity is described in Section III.13.4.2.1.2.1.1.2 of Market Rule 1.

Winter Capability Period means one of two time periods defined by the ISO for the purposes of rating and auditing resources pursuant to Section III.9. The time period associated with the Winter Capability Period is the period October 1 through May 31.

Winter Intermittent Reliability Hours are defined in Section III.13.1.2.2.2.2(c) of Market Rule 1.

Year means a period of 365 or 366 days, whichever is appropriate, commencing on, or on the anniversary of March 1, 1997. Year One is the Year commencing on March 1, 1997, and Years Two and higher follow it in sequence.

Zonal Price is calculated in accordance with Section III.2.7 of Market Rule 1.

Zonal Capacity Obligation is calculated in accordance with Section III.13.7.5.2 of Market Rule 1.

Zonal Reserve Requirement is the combined amount of TMSR, TMNSR, and TMOR required for a Reserve Zone as described in Section III.2.7A and ISO New England Operating Procedure No. 8.

STANDARD MARKET DESIGN

III.1 Market Operations

III.1.1 Introduction.

This Market Rule 1 sets forth the scheduling, other procedures, and certain general provisions applicable to the operation of the New England Markets within the New England Control Area. The ISO shall operate the New England Markets in compliance with NERC, NPCC and ISO reliability criteria. The ISO is the Counterparty for agreements and transactions with its Customers (including assignments involving Customers), including bilateral transactions described in Market Rule 1, and sales to the ISO and/or purchases from the ISO of energy, reserves, Ancillary Services, capacity, demand/load response, FTRs and other products, paying or charging (if and as applicable) its Customers the amounts produced by the pertinent market clearing process or through the other pricing mechanisms described in Market Rule 1. The bilateral transactions to which the ISO is the Counterparty (subject to compliance with the requirements of Section III.1.4) include, but are not limited to, Internal Bilaterals for Load, Internal Bilaterals for Market for Energy, Annual Reconfiguration Transactions, Capacity Supply Obligation Bilaterals, Capacity Load Obligation Bilaterals, Capacity Performance Bilaterals, and the transactions described in Sections III.9.4.1 (internal bilateral transactions that transfer Forward Reserve Obligations), and III.13.1.6 (Self-Supplied FCA Resources). Notwithstanding the foregoing, the ISO will not act as Counterparty for the import into the New England Control Area, for the use of Publicly Owned Entities, of: (1) energy, capacity, and ancillary products associated therewith, to which the Publicly Owned Entities are given preference under Articles 407 and 408 of the project license for the New York Power Authority's Niagara Project; and (2) energy, capacity, and ancillary products associated therewith, to which Publicly Owned Entities are entitled under Article 419 of the project license for the New York Power Authority's Franklin D. Roosevelt – St. Lawrence Project. This Market Rule 1 addresses each of the three time frames pertinent to the daily operation of the New England Markets: "Pre-scheduling" as specified in Section III.1.9, "Scheduling" as specified in III.1.10, and "Dispatch" as specified in III.1.11. This Market Rule 1 became effective on February 1, 2005.

III.1.2 [Reserved.]

III.1.3 Definitions.

Whenever used in Market Rule 1, in either the singular or plural number, capitalized terms shall have the meanings specified in Section I of the Tariff. Terms used in Market Rule 1 that are not defined in Section

I shall have the meanings customarily attributed to such terms by the electric utility industry in New England or as defined elsewhere in the ISO New England Filed Documents. Terms used in Market Rule 1 that are defined in Section I are subject to the 60% Participant Vote threshold specified in Section 11.1.2 of the Participants Agreement.

III.1.3.1 [Reserved.]

III.1.3.2 [Reserved.]

III.1.3.3 [Reserved.]

III.1.4 Requirements for Certain Transactions.

III.1.4.1 ISO Settlement of Certain Transactions.

The ISO will settle, and act as Counterparty to, the transactions described in Section III.1.4.2 if the transactions (and their related transactions) conform to, and the transacting Market Participants comply with, the requirements specified in Section III.1.4.3.

III.1.4.2 Transactions Subject to Requirements of Section III.1.4.

Transactions that must conform to the requirements of Section III.1.4 include: Internal Bilaterals for Load, Internal Bilaterals for Market for Energy, Annual Reconfiguration Transactions, Capacity Supply Obligation Bilaterals, Capacity Load Obligation Bilaterals, Capacity Performance Bilaterals, and the transactions described in Sections III.9.4.1 (internal bilateral transactions that transfer Forward Reserve Obligations), and III.13.1.6 (Self-Supplied FCA Resources). The foregoing are referred to collectively as "Section III.1.4 Transactions," and individually as a "Section III.1.4 Transaction." Transactions that conform to the standards are referred to collectively as "Section III.1.4 Conforming Transactions," and individually as a "Section III.1.4 Conforming Transaction."

III.1.4.3 Requirements for Section III.1.4 Conforming Transactions.

(a) To qualify as a Section III.1.4 Conforming Transaction, a Section III.1.4 Transaction must constitute an exchange for an off-market transaction (a "Related Transaction"), where the Related Transaction:

(i) is not cleared or settled by the ISO as Counterparty;

(ii) is a spot, forward or derivatives contract that contemplates the transfer of energy or a MW obligation to or from a Market Participant;

(iii) involves commercially appropriate obligations that impose a duty to transfer electricity or a MW obligation from the seller to the buyer, or from the buyer to the seller, with performance taking place within a reasonable time in accordance with prevailing cash market practices; and

(iv) is not contingent on either party to carry out the Section III.1.4 Transaction.

(b) In addition, to qualify as a Section III.1.4 Conforming Transaction:

(i) the Section III.1.4 Transaction must be executed between separate beneficial owners or separate parties trading for independently controlled accounts;

(ii) the Section III.1.4 Transaction and the Related Transaction must be separately identified in the records of the parties to the transactions; and

(iii) the Section III.1.4 Transaction must be separately identified in the records of the ISO.

(c) As further requirements:

(i) each party to the Section III.1.4 Transaction and Related Transaction must maintain, and produce upon request of the ISO, records demonstrating compliance with the requirements of Sections III.1.4.3(a) and (b) for the Section III.1.4 Transaction, the Related Transaction and any other transaction that is directly related to, or integrated in any way with, the Related Transaction, including the identity of the counterparties and the material economic terms of the transactions including their price, tenor, quantity and execution date; and

(ii) each party to the Section III.1.4 Transaction must be a Market Participant that meets all requirements of the ISO New England Financial Assurance Policy.

III.1.5 Resource Auditing.

III.1.5.1 Claimed Capability Audits.

III.1.5.1.1 General Audit Requirements.

(a) The following types of Claimed Capability Audits may be performed:

(i) An Establish Claimed Capability Audit establishes the Generator Asset’s ability to respond to ISO Dispatch Instructions and to maintain performance at a specified output level for a specified duration.

(ii) A Seasonal Claimed Capability Audit determines a Generator Asset’s capability to perform under specified summer and winter conditions for a specified duration.

(iii) A Seasonal DR Audit determines the ability of a Demand Response Resource to perform during specified months for a specified duration.

(iv) An ISO-Initiated Claimed Capability Audit is conducted by the ISO to verify the Generator Asset's Establish Claimed Capability Audit value or the Demand Response Resource's Seasonal DR Audit value.

(b) The Claimed Capability Audit value of a Generator Asset shall reflect any limitations based upon the interdependence of common elements between two or more Generator Assets such as: auxiliaries, limiting operating parameters, and the deployment of operating personnel.

(c) The Claimed Capability Audit value of gas turbine, combined cycle, and pseudo-combined cycle assets shall be normalized to standard 90° (summer) and 20° (winter) temperatures.

(d) The Claimed Capability Audit value for steam turbine assets with steam exports, combined cycle, or pseudo-combined cycle assets with steam exports where steam is exported for uses external to the electric power facility, shall be normalized to the facility's Seasonal Claimed Capability steam demand.

(e) A Claimed Capability Audit may be denied or rescheduled by the ISO if its performance will jeopardize the reliable operation of the electrical system.

III.1.5.1.2 Establish Claimed Capability Audit.

(a) An Establish Claimed Capability Audit may be performed only by a Generator Asset.

(b) The time and date of an Establish Claimed Capability Audit shall be unannounced.

(c) For a newly commercial Generator Asset:

(i) An Establish Claimed Capability Audit will be scheduled by the ISO within five Business Days of the commercial operation date for all Generator Assets except:

1. Non-intermittent daily cycle hydro;
2. Non-intermittent net-metered, or special qualifying facilities that do not elect to audit as described in Section III.1.5.1.3; and
3. Intermittent Generator Assets

(ii) The Establish Claimed Capability Audit values for both summer and winter shall equal the mean net real power output demonstrated over the duration of the audit, as reflected in hourly revenue metering data, normalized for temperature and steam exports.

(iii) The Establish Claimed Capability Audit values shall be effective as of the commercial operation date of the Generator Asset.

(d) For Generator Assets with an Establish Claimed Capability Audit value:

(i) An Establish Claimed Capability Audit may be performed at the request of a Market Participant in order to support a change in the summer and winter Establish Claimed Capability Audit values for a Generator Asset.

(ii) An Establish Claimed Capability Audit shall be performed within five Business Days of the date of the request.

(iii) The Establish Claimed Capability Audit values for both summer and winter shall equal the mean net real power output demonstrated over the duration of the audit, as reflected in hourly revenue metering data, normalized for temperature and steam exports.

(iv) The Establish Claimed Capability Audit values become effective one Business Day following notification of the audit results to the Market Participant by the ISO.

(v) A Market Participant may cancel an audit request prior to issuance of the audit Dispatch Instruction.

(e) An Establish Claimed Capability Audit value may not exceed the maximum interconnected flow specified in the Network Resource Capability for the resource associated with the Generator Asset.

(f) Establish Claimed Capability Audits shall be performed on non-NERC holiday weekdays between 0800 and 2200.

(g) To conduct an Establish Claimed Capability Audit, the ISO shall:

(i) Initiate an Establish Claimed Capability Audit by issuing a Dispatch Instruction ordering the Generator Asset's net output to increase from the current operating level to its Real-Time High Operating Limit.

(ii) Indicate when issuing the Dispatch Instruction that an audit will be conducted.

(iii) Begin the audit with the first full clock hour after sufficient time has been allowed for the asset to ramp, based on its offered ramp rate from its current operating point to reach its Real-Time High Operating Limit.

(h) An Establish Claimed Capability Audit shall be performed for the following contiguous duration:

Duration Required for an Establish Claimed Capability Audit	
Type	**Claimed Capability Audit Duration (Hrs)**
Steam Turbine (Includes Nuclear)	4
Combined Cycle	4
Integrated Coal Gasification Combustion Cycle	4
Pressurized Fluidized Bed Combustion	4

Combustion Gas Turbine	1
Internal Combustion Engine	1
Hydraulic Turbine – Reversible (Electric Storage) Hydraulic Turbine – Other	2
Hydro-Conventional Daily Pondage Hydro-Conventional Run of River Hydro-Conventional Weekly	2
Wind Photovoltaic Fuel Cell	2
Other Electric Storage (Excludes Hydraulic Turbine - Reversible)	2

(i) The ISO, in consultation with the Market Participant, will determine the contiguous audit duration for a Generator Asset of a type not listed in Section III.1.5.1.2(h).

III.1.5.1.3. Seasonal Claimed Capability Audits.

(a) A Seasonal Claimed Capability Audit may be performed only by a Generator Asset.

(b) A Seasonal Claimed Capability Audit must be conducted by all Generator Assets except:

(i) Non-intermittent daily hydro; and

(ii) Intermittent, net-metered, and special qualifying facilities. Non-intermittent net-metered and special qualifying facilities may elect to perform Seasonal Claimed Capability Audits pursuant to Section III.1.7.11(c)(iv).

(c) An Establish Claimed Capability Audit or ISO-Initiated Claimed Capability Audit that meets the requirements of a Seasonal Claimed Capability Audit in this Section III.1.5.1.3 may be used to fulfill a Generator Asset's Seasonal Claimed Capability Audit obligation.

(d) Except as provided in Section III.1.5.1.3(n) below, a summer Seasonal Claimed Capability Audit must be conducted:

(i) At least once every Capability Demonstration Year;

(ii) Either (1) at a mean ambient temperature during the audit that is greater than or equal to 80 degrees Fahrenheit at the location of the Generator Asset, or (2) during an ISO-announced summer Seasonal Claimed Capability Audit window.

(e) A winter Seasonal Claimed Capability Audit must be conducted:

(i) At least once in the previous three Capability Demonstration Years, except that a newly commercial Generator Asset which becomes commercial on or after:

(1) September 1 and prior to December 31 shall perform a winter Seasonal Claimed Capability Audit prior to the end of that Capability Demonstration Year.

(2) January 1 shall perform a winter Seasonal Claimed Capability Audit prior to the end of the next Capability Demonstration Year.

(ii) Either (1) at a mean ambient temperature during the audit that is less than or equal to 32 degrees Fahrenheit at the location of the Generator Asset, or (2) during an ISO-announced winter Seasonal Claimed Capability Audit window.

(f) A Seasonal Claimed Capability Audit shall be performed by operating the Generator Asset for the audit time period and submitting to the ISO operational data that meets the following requirements:

(i) The Market Participant must notify the ISO of its request to use the dispatch to satisfy the Seasonal Claimed Capability Audit requirement by 5:00 p.m. on the fifth Business Day following the day on which the audit concludes.

(ii) The notification must include the date and time period of the demonstration to be used for the Seasonal Claimed Capability Audit and other relevant operating data.

(g) The Seasonal Claimed Capability Audit value (summer or winter) will be the mean net real power output demonstrated over the duration of the audit, as reflected in hourly revenue metering data, normalized for temperature and steam exports.

(h) The Seasonal Claimed Capability Audit value (summer or winter) shall be the most recent audit data submitted to the ISO meeting the requirements of this Section III.1.5.1.3. In the event that a Market Participant fails to submit Seasonal Claimed Capability Audit data to meet the timing requirements in Section III.1.5.1.3(d) and (e), the Seasonal Claimed Capability Audit value for the season shall be set to zero.

(i) The Seasonal Claimed Capability Audit value shall become effective one Business Day following notification of the audit results to the Market Participant by the ISO.

(j) A Seasonal Claimed Capability Audit shall be performed for the following contiguous duration:

Duration Required for a Seasonal Claimed Capability Audit	
Type	**Claimed Capability Audit Duration (Hrs)**
Steam Turbine (Includes Nuclear)	2
Combined Cycle	2

Integrated Coal Gasification Combustion Cycle	2
Pressurized Fluidized Bed Combustion	2
Combustion Gas Turbine	1
Internal Combustion Engine	1
Hydraulic Turbine-Reversible (Electric Storage) Hydraulic Turbine-Other	2
Hydro-Conventional Weekly	2
Fuel Cell	1
Other Electric Storage (Excludes Hydraulic Turbine - Reversible)	2

(k) A Generator Asset that is on a planned outage that was approved in the ISO's annual maintenance scheduling process during all hours that meet the temperature requirements for a Seasonal Claimed Capability Audit that is to be performed by the asset during that Capability Demonstration Year shall:

(i) Submit to the ISO, prior to September 10, an explanation of the circumstances rendering it incapable of meeting these auditing requirements;

(ii) Have its Seasonal Claimed Capability Audit value for the season set to zero; and

(iii) Perform the required Seasonal Claimed Capability Audit on the next available day that meets the Seasonal Claimed Capability Audit temperature requirements.

(l) A Generator Asset that does not meet the auditing requirements of this Section III.1.5.1.3 because (1) every time the temperature requirements were met at the Generator Asset's location the ISO denied the request to operate to full capability, or (2) the temperature requirements were not met at the Generator Asset's location during the Capability Demonstration Year during which the asset was required to perform a Seasonal Claimed Capability Audit during the hours 0700 to 2300 for each weekday excluding those weekdays that are defined as NERC holidays, shall:

(i) Submit to the ISO, prior to September 10, an explanation of the circumstances rendering it incapable of meeting these temperature requirements, including verifiable temperature data;

(ii) Retain the current Seasonal Claimed Capability Audit value for the season; and

(iii) Perform the required Seasonal Claimed Capability Audit during the next Capability Demonstration Year.

(m) The ISO may issue notice of a summer or winter Seasonal Claimed Capability Audit window for some or all of the New England Control Area if the ISO determines that weather forecasts indicate that temperatures during the audit window will meet the summer or winter Seasonal

Claimed Capability Audit temperature requirements. A notice shall be issued at least 48 hours prior to the opening of the audit window. Any audit performed during the announced audit window shall be deemed to meet the temperature requirement for the summer or winter audit. In the event that five or more audit windows for the summer Seasonal Claimed Capability Audit temperature requirement, each of at least a four hour duration between 0700 and 2300 and occurring on a weekday excluding those weekdays that are defined as NERC holidays, are not opened for a Generator Asset prior to August 15 during a Capability Demonstration Year, a two-week audit window shall be opened for that Generator Asset to perform a summer Seasonal Claimed Capability Audit, and any audit performed by that Generator Asset during the open audit window shall be deemed to meet the temperature requirement for the summer Seasonal Claimed Capability Audit. The open audit window shall be between 0700 and 2300 each day during August 15 through August 31.

(n) A Market Participant that is required to perform testing on a Generator Asset that is in addition to a summer Seasonal Claimed Capability Audit may notify the ISO that the summer Seasonal Claimed Capability Audit was performed in conjunction with this additional testing, provided that:

(i) The notification shall be provided at the time the Seasonal Claimed Capability Audit data is submitted under Section III.1.5.1.3(f).

(ii) The notification explains the nature of the additional testing and that the summer Seasonal Claimed Capability Audit was performed while the Generator Asset was online to perform this additional testing.

(iii) The summer Seasonal Claimed Capability Audit and additional testing are performed during the months of June, July or August between the hours of 0700 and 2300.

(iv) In the event that the summer Seasonal Claimed Capability Audit does not meet the temperature requirements of Section III.1.5.1.3(d)(ii), the summer Seasonal Claimed Capability Audit value may not exceed the summer Seasonal Claimed Capability Audit value from the prior Capability Demonstration Year.

(v) This Section III.1.5.1.3(n) may be utilized no more frequently than once every three Capability Demonstration Years for a Generator Asset.

(o) The ISO, in consultation with the Market Participant, will determine the contiguous audit duration for a Generator Asset of a type not listed in Section III.1.5.1.3(j).

III.1.5.1.3.1 Seasonal DR Audits.

(a) A Seasonal DR Audit may be performed only by a Demand Response Resource.

(b) A Seasonal DR Audit shall be performed for 12 contiguous five-minute intervals.

(c) A summer Seasonal DR Audit must be conducted by all Demand Response Resources:

(i) At least once every Capability Demonstration Year;

(ii) During the months of April through November;

(d) A winter Seasonal DR Audit must be conducted by all Demand Response Resources:

(i) At least once every Capability Demonstration Year;

(ii) During the months of December through March.

(e) A Seasonal DR Audit may be performed either:

(i) At the request of a Market Participant as described in subsection (f) below; or

(ii) By the Market Participant designating a period of dispatch after the fact as described in subsection (g) below.

(f) If a Market Participant requests a Seasonal DR Audit:

(i) The ISO shall perform the Seasonal DR Audit at an unannounced time between 0800 and 2200 on non-NERC holiday weekdays within five Business Days of the date of the request.

(ii) The ISO shall initiate the Seasonal DR Audit by issuing a Dispatch Instruction ordering the Demand Response Resource to its Maximum Reduction.

(iii) The ISO shall indicate when issuing the Dispatch Instruction that an audit will be conducted.

(iv) The ISO shall begin the audit with the start of the first five-minute interval after sufficient time has been allowed for the resource to ramp, based on its Demand Reduction Offer parameters, to its Maximum Reduction.

(v) A Market Participant may cancel an audit request prior to issuance of the audit Dispatch Instruction.

(g) If the Seasonal DR Audit is performed by the designation of a period of dispatch after the fact, the designated period must meet all of the requirements in this Section III.1.5.1.3.1 and:

(i) The Market Participant must notify the ISO of its request to use the dispatch to satisfy the Seasonal DR Audit requirement by 5:00 p.m. on the fifth Business Day following the day on which the audit concludes.

(ii) The notification must include the date and time period of the demonstration to be used for the Seasonal DR Audit.

(iii) The demonstration period may begin with the start of any five-minute interval after the completion of the Demand Response Resource Notification Time.

(iv) A CLAIM10 audit or CLAIM30 audit that meets the requirements of a Seasonal DR Audit as provided in this Section III.1.5.1.3.1 may be used to fulfill the Seasonal DR Audit obligation of a Demand Response Resource.

(h) An ISO-Initiated Claimed Capability Audit fulfils the Seasonal DR Audit obligation of a Demand Response Resource.

(i) Each Demand Response Asset associated with a Demand Response Resource is evaluated during the Seasonal DR Audit of the Demand Response Resource.

(j) Any Demand Response Asset on a forced or scheduled curtailment as defined in Section III.8.3 is assessed a zero audit value.

(k) The Seasonal DR Audit value (summer or winter) of a Demand Response Resource resulting from the Seasonal DR Audit shall be the sum of the average demand reductions demonstrated during the audit by each of the Demand Response Resource's constituent Demand Response Assets.

(l) If a Demand Response Asset is added to or removed from a Demand Response Resource between audits, the Demand Response Resource's capability shall be updated to reflect the inclusion or exclusion of the audit value of the Demand Response Asset, such that at any point in time the summer or winter Seasonal DR Audit value of a Demand Response Resource shall equal the sum of the most recent valid like-season audit values of its constituent Demand Response Assets.

(m) The Seasonal DR Audit value shall become effective one calendar day following notification of the audit results to the Market Participant by the ISO.

(n) The summer or winter audit value of a Demand Response Asset shall be set to zero at the end of the Capability Demonstration Year if the Demand Response Asset did not perform a Seasonal DR Audit for that season as part of a Demand Response Resource during that Capability Demonstration Year.

(o) For a Demand Response Asset that was associated with a "Real-Time Demand Response Resource" or a "Real-Time Emergency Generation Resource," as those terms were defined prior to June 1, 2018, any valid result from an audit conducted prior to June 1, 2018 shall continue to be valid on June 1, 2018, and shall retain the same expiration date.

III.1.5.1.4. ISO-Initiated Claimed Capability Audits.

(a) An ISO-Initiated Claimed Capability Audit may be performed by the ISO at any time.

(b) An ISO-Initiated Claimed Capability Audit value shall replace either the summer or winter Seasonal DR Audit value for a Demand Response Resource and shall replace both the winter and summer Establish Claimed Capability Audit values for a Generator Asset, normalized for temperature and steam exports, except:

(i) The Establish Claimed Capability Audit values for a Generator Asset may not exceed the maximum interconnected flow specified in the Network Resource Capability for that resource.

(ii) An ISO-Initiated Claimed Capability Audit value for a Generator Asset shall not set the winter Establish Claimed Capability Audit value unless the ISO-Initiated Claimed Capability Audit was performed at a mean ambient temperature that is less than or equal to 32 degrees Fahrenheit at the Generator Asset location.

(c) If for a Generator Asset a Market Participant submits pressure and relative humidity data for the previous Establish Claimed Capability Audit and the current ISO-Initiated Claimed Capability Audit, the Establish Claimed Capability Audit values derived from the ISO-Initiated Claimed Capability Audit will be normalized to the pressure of the previous Establish Claimed Capability Audit and a relative humidity of 64%.

(d) The audit values derived from the ISO-Initiated Claimed Capability Audit shall become effective one Business Day following notification of the audit results to the Market Participant by the ISO.

(e) To conduct an ISO-Initiated Claimed Capability Audit, the ISO shall:

(i) Initiate an ISO-Initiated Claimed Capability Audit by issuing a Dispatch Instruction ordering the Generator Asset to its Real-Time High Operating Limit or the Demand Response Resource to its Maximum Reduction.

(ii) Indicate when issuing the Dispatch Instruction that an audit will be conducted.

(iii) For Generator Assets, begin the audit with the first full clock hour after sufficient time has been allowed for the Generator Asset to ramp, based on its offered ramp rate, from its current operating point to its Real-Time High Operating Limit.

(iv) For Demand Response Resources, begin the audit with the first five-minute interval after sufficient time has been allowed for the resource to ramp, based on its Demand Reduction Offer parameters, to its Maximum Reduction.

(f) An ISO-Initiated Claimed Capability Audit shall be performed for the following contiguous duration:

Duration Required for an ISO-Initiated Claimed Capability Audit	
Type	**Claimed Capability Audit Duration (Hrs)**
Steam Turbine (Includes Nuclear)	4
Combined Cycle	4

Integrated Coal Gasification Combustion Cycle	4
Pressurized Fluidized Bed Combustion	4
Combustion Gas Turbine	1
Internal Combustion Engine	1
Hydraulic Turbine – Reversible (Electric Storage) Hydraulic Turbine – Other	2
Hydro-Conventional Daily Pondage Hydro-Conventional Run of River Hydro-Conventional Weekly	2
Wind Photovoltaic Fuel Cell	2
Other Electric Storage (Excludes Hydraulic Turbine – Reversible)	2
Demand Response Resource	1

(g) The ISO, in consultation with the Market Participant, will determine the contiguous audit duration for an Asset or Resource type not listed in Section III.1.5.1.4(f).

III.1.5.2 ISO-Initiated Parameter Auditing.

(a) The ISO may perform an audit of any Supply Offer, Demand Reduction Offer or other operating parameter that impacts the ability of a Generator Asset or Demand Response Resource to provide real-time energy or reserves.

(b) Generator audits shall be performed using the following methods for the relevant parameter:

(i) **Economic Maximum Limit**. The Generator Asset shall be evaluated based upon its ability to achieve the current offered Economic Maximum Limit value, through a review of historical dispatch data or based on a response to a current ISO-issued Dispatch Instruction.

(ii) **Manual Response Rate**. The Generator Asset shall be evaluated based upon its ability to respond to Dispatch Instructions at its offered Manual Response Rate, including hold points and changes in Manual Response Rates.

(iii) **Start-Up Time**. The Generator Asset shall be evaluated based upon its ability to achieve the offered Start-Up Time.

(iv) **Notification Time**. The Generator Asset shall be evaluated based upon its ability to close its output breaker within its offered Notification Time.

(v) **CLAIM10**. The Generator Asset shall be evaluated based upon its ability to reach its CLAIM10 in accordance with Section III.9.5.

(vi) **CLAIM30**. The Generator Asset shall be evaluated based upon its ability to reach its CLAIM30 in accordance with Section III.9.5.

(vii) **Automatic Response Rate**. The Generator Asset shall be analyzed, based upon a review of historical performance data, for its ability to respond to four-second electronic Dispatch Instructions.

(viii) **Dual Fuel Capability**. A Generator Asset that is capable of operating on multiple fuels may be required to audit on a specific fuel, as set out in Section III.1.5.2(f).

(c) Demand Response Resource audits shall be performed using the following methods:

(i) **Maximum Reduction**. The Demand Response Resource shall be evaluated based upon its ability to achieve the current offered Maximum Reduction value, through a review of historical dispatch data or based on a response to a current Dispatch Instruction.

(ii) **Demand Response Resource Ramp Rate**. The Demand Response Resource shall be evaluated based upon its ability to respond to Dispatch Instructions at its offered Demand Response Resource Ramp Rate.

(iii) **Demand Response Resource Start-Up Time**. The Demand Response Resource shall be evaluated based upon its ability to achieve its Minimum Reduction within the offered Demand Response Resource Start-Up Time, in response to a Dispatch Instruction and after completing its Demand Response Resource Notification Time.

(iv) **Demand Response Resource Notification Time**. The Demand Response Resource shall be evaluated based upon its ability to start reducing demand within its offered Demand Response Resource Notification Time, from the receipt of a Dispatch Instruction when the Demand Response Resource was not previously reducing demand.

(v) **CLAIM10**. The Demand Response Resource shall be evaluated based upon its ability to reach its CLAIM10 in accordance with Section III.9.5.

(vi) **CLAIM30**. The Demand Response Resource shall be evaluated based upon its ability to reach its CLAIM30 in accordance with Section III.9.5.

(d) To conduct an audit based upon historical data, the ISO shall:

(i) Obtain data through random sampling of generator or Demand Response Resource performance in response to Dispatch Instructions; or

(ii) Obtain data through continual monitoring of generator or Demand Response Resource performance in response to Dispatch Instructions.

(e) To conduct an unannounced audit, the ISO shall initiate the audit by issuing a Dispatch Instruction ordering the Generator Asset or Demand Response Resource to change from the current operating level to a level that permits the ISO to evaluate the performance of the Generator Asset or Demand Response Resource for the parameters being audited.

(f) To conduct an audit of the capability of a Generator Asset described in Section III.1.5.2(b)(viii) to run on a specific fuel:

(i) The ISO shall notify the Lead Market Participant if a Generator Asset is required to undergo an audit on a specific fuel. The ISO, in consultation with the Lead Market Participant, shall develop a plan for the audit.

(ii) The Lead Market Participant will have the ability to propose the time and date of the audit within the ISO's prescribed time frame and must notify the ISO at least five Business Days in advance of the audit, unless otherwise agreed to by the ISO and the Lead Market Participant.

(g) To the extent that the audit results indicate a Market Participant is providing Supply Offer, Demand Reduction Offer or other operating parameter values that are not representative of the actual capability of the Generator Asset or Demand Response Resource, the values for the Generator Asset or Demand Response Resource shall be restricted to those values that are supported by the audit.

(h) In the event that a Generator Asset or Demand Response Resource has had a parameter value restricted:

(i) The Market Participant may submit a restoration plan to the ISO to restore that parameter. The restoration plan shall:

1. Provide an explanation of the discrepancy;
2. Indicate the steps that the Market Participant will take to re-establish the parameter's value;
3. Indicate the timeline for completing the restoration; and
4. Explain the testing that the Market Participant will undertake to verify restoration of the parameter value upon completion.

(ii) The ISO shall:

1. Accept the restoration plan if implementation of the plan, including the testing plan, is reasonably likely to support the proposed change in the parameter value restriction;
2. Coordinate with the Market Participant to perform required testing upon completion of the restoration; and
3. Modify the parameter value restriction following completion of the restoration plan, based upon tested values.

III.1.5.3 Reactive Capability Audits.

(a) Two types of Reactive Capability Audits may be performed:

(i) A lagging Reactive Capability Audit, which is an audit that measures a Reactive Resource's ability to provide reactive power to the transmission system at a specified real power output or consumption.

(ii) A leading Reactive Capability Audit, which is an audit that measures a Reactive Resource's ability to absorb reactive power from the transmission system at a specified real power output or consumption.

(b) The ISO shall develop a list of Reactive Resources that must conduct Reactive Capability Audits. The list shall include Reactive Resources that: (i) have a gross individual nameplate rating greater than 20 MVA; (ii) are directly connected, or are connected through equipment designed primarily for delivering real or reactive power to an interconnection point, to the transmission system at a voltage of 100 kV or above; and (iii) are not exempted from providing voltage control by the ISO. Additional criteria to be used in adding a Reactive Resource to the list includes, but is not limited to, the effect of the Reactive Resource on System Operating Limits, Interconnection Reliability Operating Limits, and local area voltage limits during the following operating states: normal, emergency, and system restoration.

(c) Unless otherwise directed by the ISO, Reactive Resources that are required to perform Reactive Capability Audits shall perform both a lagging Reactive Capability Audit and a leading Reactive Capability Audit.

(d) All Reactive Capability Audits shall meet the testing conditions specified in the ISO New England Operating Documents.

(e) The Reactive Capability Audit value of a Reactive Resource shall reflect any limitations based upon the interdependence of common elements between two or more Reactive Resources such as: auxiliaries, limiting operating parameters, and the deployment of operating personnel.

(f) A Reactive Capability Audit may be denied or rescheduled by the ISO if conducting the Reactive Capability Audit could jeopardize the reliable operation of the electrical system.

(g) Reactive Capability Audits shall be conducted at least every five years, unless otherwise required by the ISO. The ISO may require a Reactive Resource to conduct Reactive Capability Audits more often than every five years if:

(i) there is a change in the Reactive Resource that may affect the reactive power capability of the Reactive Resource;

(ii) there is a change in electrical system conditions that may affect the achievable reactive power output or absorption of the Reactive Resource; or

(iii) historical data shows that the amount of reactive power that the Reactive Resource can provide to or absorb from the transmission system is higher or lower than the latest audit data.

(h) A Lead Market Participant or Transmission Owner may request a waiver of the requirement to conduct a Reactive Capability Audit for its Reactive Resource. The ISO, at its sole discretion, shall determine whether and for how long a waiver may be granted.

III.1.6 [Reserved.]

III.1.6.1 [Reserved.]

III.1.6.2 [Reserved.]

III.1.6.3 [Reserved.]

III.1.6.4 ISO New England Manuals and ISO New England Administrative Procedures.

The ISO shall prepare, maintain and update the ISO New England Manuals and ISO New England Administrative Procedures consistent with the ISO New England Filed Documents. The ISO New England Manuals and ISO New England Administrative Procedures shall be available for inspection by the Market Participants, regulatory authorities with jurisdiction over the ISO or any Market Participant, and the public.

III.1.7 General.

III.1.7.1 Provision of Market Data to the Commission.

The ISO will electronically deliver to the Commission, on an ongoing basis and in a form and manner consistent with its collection of data and in a form and manner acceptable to the Commission, data related to the markets that it administers, in accordance with the Commission's regulations.

III.1.7.2 [Reserved.]

III.1.7.3 Agents.

A Market Participant may participate in the New England Markets through an agent, provided that such Market Participant informs the ISO in advance in writing of the appointment of such agent. A Market Participant using an agent shall be bound by all of the acts or representations of such agent with respect to transactions in the New England Markets, and shall ensure that any such agent complies with the

requirements of the ISO New England Manuals and ISO New England Administrative Procedures and the ISO New England Filed Documents.

III.1.7.4 [Reserved.]

III.1.7.5 Transmission Constraint Penalty Factors.

In the Day-Ahead Energy Market, the Transmission Constraint Penalty Factor for an interface constraint is $10,000/MWh and the Transmission Constraint Penalty Factor for all other transmission constraints is $30,000/MWh. In the Real-Time Energy Market, the Transmission Constraint Penalty Factor for any transmission constraint is $30,000/MWh. Transmission Constraint Penalty Factors are not used in calculating Locational Marginal Prices.

III.1.7.6 Scheduling and Dispatching.

(a) The ISO shall schedule Day-Ahead and schedule and dispatch in Real-Time Resources economically on the basis of least-cost, security-constrained dispatch and the prices and operating characteristics offered by Market Participants. The ISO shall schedule and dispatch sufficient Resources of the Market Participants to serve the New England Markets energy purchase requirements under normal system conditions of the Market Participants and meet the requirements of the New England Control Area for ancillary services provided by such Resources. The ISO shall use a joint optimization process to serve Real-Time Energy Market energy requirements and meet Real-Time Operating Reserve requirements based on a least-cost, security-constrained economic dispatch. Commencing on June 1, 2024, the ISO shall use a joint optimization process to serve Day-Ahead Energy Market energy requirements and Day-Ahead Ancillary Services requirements based on a security-constrained economic commitment and dispatch.

(b) In the event that one or more Resources cannot be scheduled in the Day-Ahead Energy Market on the basis of a least-cost, security-constrained economic commitment and dispatch as a result of one or more Self-Schedule offers contributing to a transmission limit violation, the following scheduling protocols will apply:

(i) When a single Self-Schedule offer contributes to a transmission limit violation, the Self-Schedule offer will not be scheduled for the entire Self-Schedule period in development of Day-Ahead schedules.

(ii) When two Self-Schedule offers contribute to a transmission limit violation, parallel clearing solutions will be executed such that, for each solution, one of the Self-Schedule offers will be omitted for its entire Self-Schedule period. The least cost solution will be used for purposes of determining which Resources are scheduled in the Day-Ahead Energy Market.

(iii) When three or more Self-Schedule offers contribute to a transmission limit violation, the ISO will determine the total daily MWh for each Self-Schedule offer and will omit Self-Schedule offers in their entirety, in sequence from the offer with the least total daily MWh to the offer with the greatest total MWh, stopping when the transmission limit violation is resolved.

(c) Scheduling and dispatch shall be conducted in accordance with the ISO New England Filed Documents.

(d) The ISO shall undertake, together with Market Participants, to identify any conflict or incompatibility between the scheduling or other deadlines or specifications applicable to the New England Markets, and any relevant procedures of another Control Area, or any tariff (including the Transmission, Markets and Services Tariff). Upon determining that any such conflict or incompatibility exists, the ISO shall propose tariff or procedural changes, or undertake such other efforts as may be appropriate, to resolve any such conflict or incompatibility.

III.1.7.7 Energy Pricing.

The price paid for energy, including demand reductions, bought and sold by the ISO in the New England Markets will reflect the Locational Marginal Price at each Location, determined by the ISO in accordance with the ISO New England Filed Documents. Congestion Costs, which shall be determined by differences in the Congestion Component of Locational Marginal Prices caused by constraints, shall be calculated and collected, and the resulting revenues disbursed, by the ISO in accordance with this Market Rule 1. Loss costs associated with Pool Transmission Facilities, which shall be determined by the differences in Loss Components of the Locational Marginal Prices shall be calculated and collected, and the resulting revenues disbursed, by the ISO in accordance with this Market Rule 1.

III.1.7.8 Market Participant Resources.

A Market Participant may elect to Self-Schedule its Resources in accordance with and subject to the limitations and procedures specified in this Market Rule 1 and the ISO New England Manuals.

III.1.7.8A Day-Ahead Ancillary Services Prices.

The prices paid by the ISO for the provision of Day-Ahead Ancillary Services in the New England Markets will reflect Day-Ahead Ancillary Services clearing prices determined by the ISO in accordance with the ISO New England Filed Documents.

III.1.7.9 Real-Time Reserve Prices.

The price paid by the ISO for the provision of Real-Time Operating Reserve in the New England Markets will reflect Real-Time Reserve Clearing Prices determined by the ISO in accordance with the ISO New England Filed Documents for the system and each Reserve Zone.

III.1.7.10 Other Transactions.

Market Participants may enter into internal bilateral transactions and External Transactions for the purchase or sale of energy or other products to or from each other or any other entity, subject to the obligations of Market Participants to make resources with a Capacity Supply Obligation available for dispatch by the ISO. External Transactions that contemplate the physical transfer of energy or obligations to or from a Market Participant shall be reported to and coordinated with the ISO in accordance with this Market Rule 1 and the ISO New England Manuals.

III.1.7.11 Seasonal Claimed Capability of a Generating Capacity Resource.

(a) A Seasonal Claimed Capability value must be established and maintained for all Generating Capacity Resources. A summer Seasonal Claimed Capability is established for use from June 1 through September 30 and a winter Seasonal Claimed Capability is established for use from October 1 through May 31.

(b) The Seasonal Claimed Capability of a Generating Capacity Resource is the sum of the Seasonal Claimed Capabilities of the Generator Assets that are associated with the Generating Capacity Resource.

(c) The Seasonal Claimed Capability of a Generator Asset is:

(i) Based upon review of historical data for non-intermittent daily cycle hydro.

(ii) The median net real power output during reliability hours, as described in Section III.13.1.2.2.2, for (1) intermittent facilities, and (2) net-metered and special qualifying facilities that do not elect to audit, as reflected in hourly revenue metering data.

(iii) For non-intermittent net-metered and special qualifying facilities that elect to audit, the minimum of (1) the Generator Asset's current Seasonal Claimed Capability Audit value, as performed

pursuant to Section III.1.5.1.3; (2) the Generator Asset's current Establish Claimed Capability Audit value; and (3) the median hourly availability during hours ending 2:00 p.m. through 6:00 p.m. each day of the preceding June through September for Summer and hours ending 6:00 p.m. and 7:00 p.m. each day of the preceding October through May for Winter. The hourly availability:

a. For a Generator Asset that is available for commitment and following Dispatch Instructions, shall be the asset's Economic Maximum Limit, as submitted or redeclared.
b. For a Generator Asset that is off-line and not available for commitment shall be zero.
c. For a Generator Asset that is on-line but not able to follow Dispatch Instructions, shall be the asset's metered output.

(iv) For all other Generator Assets, the minimum of: (1) the Generator Asset's current Establish Claimed Capability Audit value and (2) the Generator Asset's current Seasonal Claimed Capability Audit value, as performed pursuant to Section III.1.5.1.3.

III.1.7.12 Seasonal DR Audit Value of an Active Demand Capacity Resource.

(a) A Seasonal DR Audit value must be established and maintained for all Active Demand Capacity Resources. A summer Seasonal DR Audit value is established for use from April 1 through November 30 and a winter Seasonal DR Audit value is established for use from December 1 through March 31.

(b) The Seasonal DR Audit value of an Active Demand Capacity Resource is the sum of the Seasonal DR Audit values of the Demand Response Resources that are associated with the Active Demand Capacity Resource.

III.1.7.13 [Reserved.]

III.1.7.14 [Reserved.]

III.1.7.15 [Reserved.]

III.1.7.16 [Reserved.]

III.1.7.17 Operating Reserve.

The ISO shall endeavor to procure and maintain an amount of Operating Reserve in Real-Time equal to the system and zonal Operating Reserve requirements as specified in the ISO New England Manuals and ISO New England Administrative Procedures. Reserve requirements for the Forward Reserve Market are determined in accordance with the methodology specified in Section III.9.2 of Market Rule 1. Operating

Reserve requirements for Real-Time dispatch within an Operating Day are determined in accordance with Market Rule 1 and ISO New England Operating Procedure No. 8, Operating Reserve and Regulation.

III.1.7.18 Ramping.

A Generator Asset, Dispatchable Asset Related Demand, or Demand Response Resource dispatched by the ISO pursuant to a control signal appropriate to increase or decrease the Resource's megawatt output, consumption, or demand reduction level shall be able to change output, consumption, or demand reduction at the ramping rate specified in the Offer Data submitted to the ISO for that Resource and shall be subject to sanctions for failure to comply as described in **Appendix B**.

III.1.7.19 Real-Time Reserve Designation.

The ISO shall determine the Real-Time Reserve Designation for each eligible Resource in accordance with this Section III.1.7.19. The Real-Time Reserve Designation shall consist of a MW value, in no case less than zero, for each Operating Reserve product: Ten-Minute Spinning Reserve, Ten-Minute Non-Spinning Reserve, and Thirty-Minute Operating Reserve.

III.1.7.19.1 Eligibility.

To be eligible to receive a Real-Time Reserve Designation, a Resource must meet all of the criteria enumerated in this Section III.1.7.19.1. A Resource that does not meet all of these criteria is not eligible to provide Operating Reserve and will not receive a Real-Time Reserve Designation.

(1) The Resource must be a Dispatchable Resource located within the metered boundaries of the New England Control Area and capable of receiving and responding to electronic Dispatch Instructions.

(2) The Resource must not be part of the first contingency supply loss.

(3) The Resource must not be designated as constrained by transmission limitations.

(4) The Resource's Operating Reserve, if activated, must be sustainable for at least one hour from the time of activation. (This eligibility requirement does not affect a Resource's obligation to follow Dispatch Instructions, even after one hour from the time of activation.)

(5) The Resource must comply with the applicable standards and requirements for provision and dispatch of Operating Reserve as specified in the ISO New England Manuals and ISO New England Administrative Procedures.

III.1.7.19.2 Calculation of Real-Time Reserve Designation.

III.1.7.19.2.1 Generator Assets.

III.1.7.19.2.1.1 On-line Generator Assets.

The Manual Response Rate used in calculations in this section shall be the lesser of the Generator Asset's offered Manual Response Rate and its audited Manual Response Rate as described in Section III.1.5.2.

(a) **Ten-Minute Spinning Reserve.** For an on-line Generator Asset (other than one registered as being composed of multiple generating units whose synchronized capability cannot be determined by the ISO), Ten-Minute Spinning Reserve shall be calculated as the increase in output the Generator Asset could achieve, relative to its current telemetered output, within ten minutes given its Manual Response Rate (and in no case to a level greater than its Economic Maximum Limit). For an on-line Generator Asset registered as being composed of multiple generating units whose synchronized capability cannot be determined by the ISO, Ten-Minute Spinning Reserve shall be zero.

(b) **Ten-Minute Non-Spinning Reserve.** For an on-line Generator Asset (other than one registered as being composed of multiple generating units whose synchronized capability cannot be determined by the ISO), Ten-Minute Non-Spinning Reserve shall be zero. For an on-line Generator Asset registered as being composed of multiple generating units whose synchronized capability cannot be determined by the ISO, Ten-Minute Non-Spinning Reserve shall be calculated as the increase in output the Generator Asset could achieve, relative to its current telemetered output, within ten minutes given its Manual Response Rate (and in no case to a level greater than its Economic Maximum Limit).

(c) **Thirty-Minute Operating Reserve.** For an on-line Generator Asset, Thirty-Minute Operating Reserve shall be calculated as the increase in output the Generator Asset could achieve, relative to its current telemetered output, within thirty minutes given its Manual Response Rate (and in no case greater than its Economic Maximum Limit) minus the Ten-Minute Spinning Reserve quantity calculated for the Generator Asset pursuant to subsection (a) above and the Ten-Minute Non-Spinning Reserve quantity calculated for the Generator Asset pursuant to subsection (b) above.

III.1.7.19.2.1.2 Off-line Generator Assets.

For an off-line Generator Asset that is not a Fast Start Generator, all components of the Real-Time Reserve Designation shall be zero.

(a) **Ten-Minute Spinning Reserve.** For an off-line Fast Start Generator, Ten-Minute Spinning Reserve shall be zero.

(b) **Ten-Minute Non-Spinning Reserve.** For an off-line Fast Start Generator, Ten-Minute Non-Spinning Reserve shall be calculated as the minimum of the Fast Start Generator's Offered CLAIM10, its CLAIM10, and its Economic Maximum Limit (provided, however, that during the Fast Start Generator's Minimum Down Time, the Fast Start Generator's Ten-Minute Non-Spinning Reserve shall be zero, except during the last ten minutes of its Minimum Down Time, at which time the ISO will prorate the Fast Start Generator's Ten-Minute Non-Spinning Reserve to account for the remaining amount of time until the Fast Start Generator's Minimum Down Time expires).

(c) **Thirty-Minute Operating Reserve.** For an off-line Fast Start Generator, Thirty-Minute Operating Reserve shall be calculated as: (i) the minimum of the Fast Start Generator's Offered CLAIM30, its CLAIM30, and its Economic Maximum Limit (provided, however, that during the Fast Start Generator's Minimum Down Time, the Fast Start Generator's Thirty-Minute Operating Reserve shall be zero, except during the last thirty minutes of its Minimum Down Time, at which time the ISO will prorate the Fast Start Generator's Thirty-Minute Operating Reserve to account for the remaining amount of time until the Fast Start Generator's Minimum Down Time expires), minus (ii) the Ten-Minute Non-Spinning Reserve quantity calculated for the Fast Start Generator pursuant to subsection (b) above.

III.1.7.19.2.2 Dispatchable Asset Related Demand.

III.1.7.19.2.2.1 Storage DARDs.

(a) **Ten-Minute Spinning Reserve.** For a Storage DARD, Ten-Minute Spinning Reserve shall be calculated as the absolute value of the amount of current telemetered consumption.

(b) **Ten-Minute Non-Spinning Reserve.** For a Storage DARD, Ten-Minute Non-Spinning Reserve shall be zero.

(c) **Thirty-Minute Operating Reserve.** For a Storage DARD, Thirty-Minute Operating Reserve shall be zero.

III.1.7.19.2.2.2 Dispatchable Asset Related Demand Other Than Storage DARDs.

(a) **Ten-Minute Spinning Reserve.** For a Dispatchable Asset Related Demand (other than a Storage DARD) that has no Controllable Behind-the-Meter Generation, Ten-Minute Spinning Reserve shall be calculated as the decrease in consumption that the Dispatchable Asset Related Demand could achieve, relative to its current telemetered consumption, within ten minutes given its ramp rate (and in no case to an amount less than its Minimum Consumption Limit). For a Dispatchable Asset Related Demand (other than a Storage DARD) having Controllable Behind-the-Meter Generation, Ten-Minute Spinning Reserve shall be zero.

(b) **Ten-Minute Non-Spinning Reserve.** For a Dispatchable Asset Related Demand (other than a Storage DARD) that has no Controllable Behind-the-Meter Generation, Ten-Minute Non-Spinning Reserve shall be zero. For a Dispatchable Asset Related Demand (other than a Storage DARD) having Controllable Behind-the-Meter Generation, Ten-Minute Non-Spinning Reserve shall be calculated as the decrease in consumption that the Dispatchable Asset Related Demand could achieve, relative to its current telemetered consumption, within ten minutes given its ramp rate (and in no case to an amount less than its Minimum Consumption Limit).

(c) **Thirty-Minute Operating Reserve.** For a Dispatchable Asset Related Demand (other than a Storage DARD) that has no Controllable Behind-the-Meter Generation, Thirty-Minute Operating Reserve shall be calculated as the decrease in consumption that the Dispatchable Asset Related Demand could achieve, relative to its current telemetered consumption, within thirty minutes given its ramp rate (and in no case to an amount less than its Minimum Consumption Limit) minus the Ten-Minute Spinning Reserve quantity calculated for the Dispatchable Asset Related Demand pursuant to subsection (a) above. For a Dispatchable Asset Related Demand (other than a Storage DARD) having Controllable Behind-the-Meter Generation, Thirty-Minute Operating Reserve shall be calculated as the decrease in consumption that the Dispatchable Asset Related Demand could achieve, relative to its current telemetered consumption, within thirty minutes given its ramp rate (and in no case to an amount less than its Minimum Consumption Limit)

minus the Ten-Minute Non-Spinning Reserve quantity calculated for the Dispatchable Asset Related Demand pursuant to subsection (b) above.

III.1.7.19.2.3 Demand Response Resources.

For a Demand Response Resource that does not provide one-minute telemetry to the ISO, notwithstanding any provision in this Section III.1.7.19.2.3 to the contrary, the Ten-Minute Spinning Reserve and Ten-Minute Non-Spinning Reserve components of the Real-Time Reserve Designation shall be zero. The Demand Response Resource Ramp Rate used in calculations in this section shall be the lesser of the Resource's offered Demand Response Resource Ramp Rate and its audited Demand Response Resource Ramp Rate as described in Section III.1.5.2.

III.1.7.19.2.3.1 Dispatched.

(a) **Ten-Minute Spinning Reserve.** For a Demand Response Resource that is being dispatched and that has no Controllable Behind-the-Meter Generation, Ten-Minute Spinning Reserve shall be calculated as the increase in demand reduction that the Demand Response Resource could achieve, relative to the estimated current demand reduction level, within ten minutes given its Demand Response Resource Ramp Rate (and in no case greater than its Maximum Reduction). For a Demand Response Resource that is being dispatched and that has Controllable Behind-the-Meter Generation, Ten-Minute Spinning Reserve shall be zero.

(b) **Ten-Minute Non-Spinning Reserve.** For a Demand Response Resource that is being dispatched and that has no Controllable Behind-the-Meter Generation, Ten-Minute Non-Spinning Reserve shall be zero. For a Demand Response Resource that is being dispatched and that has Controllable Behind-the-Meter Generation, Ten-Minute Non-Spinning Reserve shall be calculated as the increase in demand reduction that the Demand Response Resource could achieve, relative to the estimated current demand reduction level, within ten minutes given its Demand Response Resource Ramp Rate (and in no case greater than its Maximum Reduction).

(c) **Thirty-Minute Operating Reserve.** For a Demand Response Resource that is being dispatched, Thirty-Minute Operating Reserve shall be calculated as the increase in demand reduction that the Demand Response Resource could achieve, relative to the estimated current demand reduction level, within thirty minutes given its Demand Response Resource Ramp Rate (and in no case greater than its Maximum Reduction) minus the Ten-Minute Spinning Reserve quantity

calculated for the Resource pursuant to subsection (a) above and the Ten-Minute Non-Spinning Reserve quantity calculated for the Resource pursuant to subsection (b) above.

III.1.7.19.2.3.2 Non-Dispatched.

For a Demand Response Resource that is not being dispatched that is not a Fast Start Demand Response Resource, all components of the Real-Time Reserve Designation shall be zero.

(a) **Ten-Minute Spinning Reserve.** For a Fast Start Demand Response Resource that is not being dispatched, Ten-Minute Spinning Reserve shall be zero.

(b) **Ten-Minute Non-Spinning Reserve.** For a Fast Start Demand Response Resource that is not being dispatched, Ten-Minute Non-Spinning Reserve shall be calculated as the minimum of the Demand Response Resource's Offered CLAIM10, its CLAIM10, and its Maximum Reduction.

(c) **Thirty-Minute Operating Reserve.** For a Fast Start Demand Response Resource that is not being dispatched, Thirty-Minute Operating Reserve shall be calculated as: (i) the minimum of the Demand Response Resource's Offered CLAIM30, its CLAIM30, and its Maximum Reduction, minus (ii) the Ten-Minute Non-Spinning Reserve quantity calculated for the Demand Response Resource pursuant to subsection (b) above.

III.1.7.20 Information and Operating Requirements.

(a) [Reserved.]

(b) Market Participants selling from Resources within the New England Control Area shall: supply to the ISO all applicable Offer Data; report to the ISO Resources that are Self-Scheduled; report to the ISO External Transaction sales; confirm to the ISO bilateral sales to Market Participants within the New England Control Area; respond to the ISO's directives to start, shutdown or change output, consumption, or demand reduction levels of Generator Assets, DARDs, or Demand Response Resources, change scheduled voltages or reactive output levels; continuously maintain all Offer Data concurrent with on-line operating information; and ensure that, where so equipped, equipment is operated with control equipment functioning as specified in the ISO New England Manuals and ISO New England Administrative Procedures.

(c) Market Participants selling from Resources outside the New England Control Area shall: provide to the ISO all applicable Offer Data, including offers specifying amounts of energy available, hours of availability and prices of energy and other services; respond to ISO directives to schedule delivery or change delivery schedules; and communicate delivery schedules to the source Control Area and any intermediary Control Areas.

(d) Market Participants, as applicable, shall: respond or ensure a response to ISO directives for load management steps; report to the ISO all bilateral purchase transactions including External Transaction purchases; and respond or ensure a response to other ISO directives such as those required during Emergency operation.

(e) Market Participant, as applicable, shall provide to the ISO requests to purchase specified amounts of energy for each hour of the Operating Day during which it intends to purchase from the Day-Ahead Energy Market.

(f) Market Participants are responsible for reporting to the ISO anticipated availability and other information concerning Generator Assets, Demand Response Resources and Dispatchable Asset Related Demands required by the ISO New England Operating Documents, including but not limited to the Market Participant's ability to procure fuel and physical limitations that could reduce Resource output or demand reduction capability for the pertinent Operating Day.

III.1.8 ~~[Reserved.]~~Energy Call Option Offers and Day-Ahead Ancillary Services Demand Quantities.

III.1.8.1 Applicability.

The provisions of this Section III.1.8 apply commencing on June 1, 2024.

III.1.8.2 Energy Call Option Offers.

Market Participants may submit Energy Call Option Offers for the Operating Day as specified in this Section III.1.8.2.

(a) Each Energy Call Option Offer shall be associated with a specific Generator Asset or Demand Response Resource for which the Market Participant has submitted a corresponding Supply Offer or Demand Reduction Offer in the Day-Ahead Energy Market for the same hour of the Operating Day.

(b) Each Energy Call Option Offer shall specify: (i) the hour of the Operating Day for which the Energy Call Option Offer applies; (ii) an offer price, in $/MWh, that is greater than or equal to zero; and (iii) an offer quantity, in MWh, that is greater than or equal to zero. The offer price shall not exceed the Reserve Constraint Penalty Factor value specified in Section III.2.6.2(b)(vi) of this Market Rule 1. The offer quantity shall not exceed the Economic Maximum Limit specified in the associated Supply Offer or the Maximum Reduction specified in the associated Demand Reduction Offer.

(c) For each hour of the Operating Day, a Market Participant may submit only one Energy Call Option Offer associated with a specific Generator Asset or Demand Response Resource.

(d) Energy Call Option Offers shall be submitted by the offer submission deadline for the Day-Ahead Energy Market specified in Section III.1.10.1A of this Market Rule 1. An Energy Call Option Offer shall not remain in effect for subsequent Operating Days.

III.1.8.3 Energy Call Option Strike Price.

For each hour of the Operating Day, the ISO shall specify the Energy Call Option Strike Price in $/MWh. The value of the Energy Call Option Strike Price shall represent a forecast of the expected hourly Real-Time Hub Price for each hour of the Operating Day plus $10/MWh.

The forecast used to determine the Energy Call Option Strike Price shall be based on a publicly-available forecasting algorithm. The ISO shall identify the publicly-available forecasting algorithm and shall review any potential revisions to the forecasting process, prospectively, through the stakeholder process.

The ISO shall post, publicly, the value of the Energy Call Option Strike Price for each hour of the Operating Day no later than two hours before the offer submission deadline for the Day-Ahead Energy Market specified in Section III.1.10.1A of this Market Rule 1, or such other time as necessary to account for software failures or other events.

III.1.8.4 [Reserved.]

III.1.8.5 Day-Ahead Ancillary Services Demand Quantities.

The Day-Ahead Energy Market shall endeavor to procure the demand quantities for the Day-Ahead Ancillary Services specified in this Section III.1.8.5.

(a) For each hour of the Operating Day, the Day-Ahead Ten-Minute Spinning Reserve Demand Quantity shall be equal to the projected Ten-Minute Spinning Reserve Requirement as described in Section III.2.7A of this Market Rule 1 and ISO New England Operating Procedure No. 8.

(b) For each hour of the Operating Day, the Day-Ahead Total Ten-Minute Reserve Demand Quantity shall be equal to the projected Ten-Minute Reserve Requirement as described in Section III.2.7A of this Market Rule 1 and ISO New England Operating Procedure No. 8.

(c) For each hour of the Operating Day, the Day-Ahead Total Thirty-Minute Operating Reserve Demand Quantity shall be equal to the projected Minimum Total Reserve Requirement as described in Section III.2.7A of this Market Rule 1 and ISO New England Operating Procedure No. 8.

(d) For each hour of the Operating Day from December 1 through February 28/29, the Day-Ahead Total Ninety-Minute Reserve Demand Quantity shall be the reserve capability sufficient to satisfy the requirements in NERC Reliability Standard BAL-002-3 – Disturbance Control Standard – Contingency Reserve for Recovery from a Balancing Contingency Event, including the restoration of Contingency Reserve within the Contingency Reserve Restoration Period. For each hour of the Operating Day from March 1 through November 30, the Day-Ahead Total Ninety-Minute Reserve Demand Quantity shall be zero.

(e) For each hour of the Operating Day from December 1 through February 28/29, the Day-Ahead Total Four-Hour Reserve Demand Quantity shall be the reserve capability sufficient to satisfy the requirements of NPCC Regional Reliability Reference Directory No. 5 Reserve, including the restoration of Thirty-Minute Operating Reserve within four hours of a deficiency. For each hour of the Operating Day from March 1 through November 30, the Day-Ahead Total Four-Hour Reserve Demand Quantity shall be zero.

(f) For each hour of the Operating Day, the Day-Ahead Energy Imbalance Reserve Demand Quantity shall be determined during the scheduling of the Day-Ahead Energy Market. The Day-Ahead Energy Imbalance Reserve Demand Quantity shall be equal to the greater of (a) zero or (b) the value of:
(i) the Forecast Energy Requirement Demand Quantity; less (ii) the sum of the total MWh of all Supply Offers and the total MWh of all Demand Reduction Offers that receive the forecast energy requirement

credit, as specified in Section III.3.2.1(q)(5); less (iii) the net total External Transactions (imports minus exports, in MWh) scheduled in the Day-Ahead Energy Market.

III.1.8.6 Forecast Energy Requirement Demand Quantity.

For each hour of the Operating Day, the Forecast Energy Requirement Demand Quantity shall be equal to the ISO forecast for the total loads in the New England Control Area produced pursuant to Section III.1.10.1.A(h) of this Market Rule 1.

III.1.9 Pre-scheduling.

III.1.9.1 Offer and Bid Caps and Cost Verification for Offers and Bids.

III.1.9.1.1 Cost Verification of Resource Offers.

The incremental energy values of Supply Offers and Demand Response Resources above $1,000/MWh for any Resource other than an External Resource are subject to the following cost verification requirements. Unless expressly stated otherwise, cost verification is utilized in all pricing, commitment, dispatch and settlement determinations. For purposes of the following requirements, Reference Levels are calculated using the procedures in Section III.A.7.5 for calculating cost-based Reference Levels.

(a) If the incremental energy value of a Resource's offer is greater than the incremental energy Reference Level value of the Resource, then the incremental energy value in the offer is replaced with the greater of the Reference Level for incremental energy or $1,000/MWh.

(b) For purposes of the price calculations in Sections III.2.5 and III.2.7A, if the adjusted offer calculated under Section III.2.4 for a Rapid Response Pricing Asset is greater than $1,000/MWh (after the incremental energy value is evaluated under Section III.1.9.1.1(a) above), then verification will be performed as follows using a Reference Level value calculated with the adjusted offer formulas specified in Section III.2.4.

(i) If the Reference Level value is less than or equal to $1,000/MWh, then the adjusted offer for the Resource is set at $1,000/MWh;

(ii) If the Reference Level value is greater than $1,000/MWh, then the adjusted offer for the Resource is set at the lower of the Reference Level value and the adjusted offer.

III.1.9.1.2 Offer and Bid Caps.

(a) For purposes of the price calculations described in Section III.2 and for purposes of scheduling a Resource in the Day-Ahead Energy Market in accordance with Section III.1.7.6 following the commitment of the Resource, the incremental energy value of an offer is capped at $2,000/MWh.

(b) Demand Bids shall not specify a bid price below the Energy Offer Floor or above the Demand Bid Cap.

(c) Supply Offers shall not specify an offer price (for incremental energy) below the Energy Offer Floor.

(d) External Transactions shall not specify a price below the External Transaction Floor or above the External Transaction Cap.

(e) Increment Offers and Decrement Bids shall not specify an offer or bid price below the Energy Offer Floor or above the Virtual Cap.

III.1.9.2 [Reserved.]

III.1.9.3 [Reserved.]

III.1.9.4 [Reserved.]

III.1.9.5 [Reserved.]

III.1.9.6 [Reserved.]

III.1.9.7 Market Participant Responsibilities.

Market Participants authorized and intending to request market-based Start-Up Fees and No-Load Fee in their Offer Data shall submit a specification of such fees to the ISO for each Generator Asset as to which the Market Participant intends to request such fees. Any such specification shall identify the applicable period and be submitted on or before the applicable deadline and shall remain in effect unless otherwise modified in accordance with Section III.1.10.9. The ISO shall reject any request for Start-Up Fees and No-Load Fee in a Market Participant's Offer Data that does not conform to the Market Participant's specification on file with the ISO.

III.1.9.8 [Reserved.]

III.1.10 Scheduling.

III.1.10.1 General.

(a) The ISO shall administer scheduling processes to implement a Day-Ahead Energy Market and a Real-Time Energy Market.

(b) The Day-Ahead Energy Market shall enable Market Participants to purchase and sell energy and, commencing on June 1, 2024, sell ancillary services through the New England Markets at the applicable Day-Ahead Prices, and enable Market Participants to submit External Transactions conditioned upon Congestion Costs not exceeding a specified level. Market Participants whose purchases and sales and External Transactions are scheduled in the Day-Ahead Energy Market shall be obligated to purchase or sell energy or pay Congestion Costs and costs for losses, at the applicable Day-Ahead Prices for the amounts scheduled.

(c) In the Real-Time Energy Market,

(i) Market Participants that deviate from the amount of energy purchases or sales scheduled in the Day-Ahead Energy Market shall replace the energy not delivered with energy from the Real-Time Energy Market or an internal bilateral transaction and shall pay for such energy not delivered, net of any internal bilateral transactions, at the applicable Real-Time Price, unless otherwise specified by this Market Rule 1, and

(ii) Non-Market Participant Transmission Customers shall be obligated to pay Congestion Costs and costs for losses for the amount of the scheduled transmission uses in the Real-Time Energy Market at the applicable Real-Time Congestion Component and Loss Component price differences, unless otherwise specified by this Market Rule 1.

(d) The following scheduling procedures and principles shall govern the commitment of Resources to the Day-Ahead Energy Market and the Real-Time Energy Market over a period extending from one week to one hour prior to the Real-Time dispatch. Scheduling encompasses the Day-Ahead and hourly scheduling process, through which the ISO determines the Day-Ahead Energy Market schedule and determines, based on changing forecasts of conditions and actions by Market Participants and system constraints, a plan to serve the hourly energy and reserve requirements of the New England Control Area in the least costly manner, subject to maintaining the reliability of the New England Control Area. Scheduling of External Transactions in the Real-Time Energy Market is subject to Section II.44 of the OATT.

(e) If the ISO's forecast for the next seven days projects a likelihood of Emergency Condition, the ISO may commit, for all or part of such seven day period, to the use of Generator Assets or Demand Response Resources with Notification Time greater than 24 hours as necessary in order to alleviate or mitigate such Emergency, in accordance with the Market Participants' binding Supply Offers or Demand Reduction Offers.

III.1.10.1A Energy Market Scheduling.

The submission of Day-Ahead offers and bids shall occur not later than 10:00 a.m. on the day before the Operating Day for which transactions are being scheduled, or such other deadline as may be specified by the ISO in order to comply with the practical requirements and the economic and efficiency objectives of the scheduling process specified in this Market Rule 1.

(a) **Locational Demand Bids –** Each Market Participant may submit to the ISO specifications of the amount and location of its customer loads and/or energy purchases to be included in the Day-Ahead Energy Market for each hour of the next Operating Day, such specifications to comply with the requirements set forth in the ISO New England Manuals and ISO New England Administrative Procedures. Each Market Participant shall inform the ISO of (i) the prices, if any, at which it desires not to include its load in the Day-Ahead Energy Market rather than pay the applicable Day-Ahead Price, (ii) hourly schedules for Resources Self-Scheduled by the Market Participant; and (iii) the Decrement Bid at which each such Self-Scheduled Resource will disconnect or reduce output, or confirmation of the Market Participant's intent not to reduce output. Price-sensitive Demand Bids and Decrement Bids must be greater than zero MW and shall not exceed the Demand Bid Cap and Virtual Cap.

(b) **External Transactions –** All Market Participants shall submit to the ISO schedules for any External Transactions involving use of Generator Assets or the New England Transmission System as specified below, and shall inform the ISO whether the transaction is to be included in the Day-Ahead Energy Market. Any Market Participant that elects to include an External Transaction in the Day-Ahead Energy Market may specify the price (such price not to exceed the maximum price that may be specified in the ISO New England Manuals and ISO New England Administrative Procedures), if any, at which it will be curtailed rather than pay Congestion Costs. The foregoing price specification shall apply to the price difference between the Locational Marginal Prices for specified External Transaction source and sink points in the Day-Ahead scheduling process only. Any Market Participant that deviates from its Day-Ahead External Transaction schedule or elects not to include its External Transaction in the Day-Ahead Energy Market shall be subject to Congestion Costs in the Real-Time Energy Market in order to complete any such scheduled External Transaction. Scheduling of External Transactions shall be conducted in accordance with the specifications in the ISO New England Manuals and ISO New England Administrative Procedures and the following requirements:

(i) Market Participants shall submit schedules for all External Transaction purchases for delivery within the New England Control Area from Resources outside the New England Control Area;

(ii) Market Participants shall submit schedules for External Transaction sales to entities outside the New England Control Area from Resources within the New England Control Area;

(iii) In the Day-Ahead Energy Market, if the sum of all submitted Self-Scheduled External Transaction purchases less External Transaction sales exceeds the import capability associated with the applicable External Node, the offer prices for all Self-Scheduled External Transaction purchases at the applicable External Node shall be set equal to the Energy Offer Floor;

(iv) In the Day-Ahead Energy Market, if the sum of all submitted Self-Scheduled External Transaction sales less External Transaction purchases exceeds the export capability associated with the applicable External Node, the offer prices for all Self-Scheduled External Transaction sales at the applicable External Node shall be set equal to the External Transaction Cap;

(v) The ISO shall not consider Start-Up Fees, No-Load Fees, Notification Times or any other inter-temporal parameters in scheduling or dispatching External Transactions.

(c) **Generator Asset Supply Offers –** Market Participants selling into the New England Markets from Generator Assets may submit Supply Offers for the supply of energy for the following Operating Day.

Such Supply Offers:

(i) Shall specify the Resource and Blocks (price and quantity of Energy) for each hour of the Operating Day for each Resource offered by the Market Participant to the ISO. The prices and quantities in a Block may each vary on an hourly basis;

(ii) If based on energy from a Generator Asset internal to the New England Control Area, may specify, for Supply Offers, a Start-Up Fee and No-Load Fee for each hour of the Operating Day. Start-Up Fee and No-Load Fee may vary on an hourly basis;

(iii) Shall specify, for Supply Offers from a dual-fuel Generator Asset, the fuel type. The fuel type may vary on an hourly basis. A Market Participant that submits a Supply Offer using the higher cost fuel type must satisfy the consultation requirements for dual-fuel Generator Assets in Section III.A.3 of Appendix A;

(iv) Shall specify a Minimum Run Time to be used for commitment purposes that does not exceed 24 hours;

(v) Supply Offers shall constitute an offer to submit the Generator Asset to the ISO for commitment and dispatch in accordance with the terms of the Supply Offer, where such Supply Offer, with regard to operating limits, shall specify changes, including to the Economic Maximum Limit, Economic Minimum Limit and Emergency Minimum Limit, from those submitted as part of the Resource's Offer Data to reflect the physical operating characteristics and/or availability of the Resource (except that for a Limited Energy Resource, the Economic Maximum Limit may be revised to reflect an energy (MWh) limitation), which offer shall remain open through the Operating Day for which the Supply Offer is submitted; and

(vi) Shall, in the case of a Supply Offer from a Generator Asset associated with an Electric Storage Facility, also meet the requirements specified in Section III.1.10.6.

(d) DARD Demand Bids – Market Participants participating in the New England Markets with Dispatchable Asset Related Demands may submit Demand Bids for the consumption of energy for the following Operating Day.

Such Demand Bids:

(i) Shall specify the Dispatchable Asset Related Demand and Blocks (price and Energy quantity pairs) for each hour of the Operating Day for each Dispatchable Asset Related Demand offered by the Market Participant to the ISO. The prices and quantities in a Block may each vary on an hourly basis;

(ii) Shall constitute an offer to submit the Dispatchable Asset Related Demand to the ISO for commitment and dispatch in accordance with the terms of the Demand Bid, where such Demand Bid, with regard to operating limits, shall specify changes, including to the Maximum Consumption Limit and Minimum Consumption Limit, from those submitted as part of the Resource's Offer Data to reflect the physical operating characteristics and/or availability of the Resource;

(iii) Shall specify a Minimum Consumption Limit that is less than or equal to its Nominated Consumption Limit; and

(iv) Shall, in the case of a Demand Bid from a Storage DARD, also meet the requirements specified in Section III.1.10.6.

(e) **Demand Response Resource Demand Reduction Offers –** Market Participants selling into the New England Markets from Demand Response Resources may submit Demand Reduction Offers for the supply of energy for the following Operating Day. A Demand Reduction Offer shall constitute an offer to submit the Demand Response Resource to the ISO for commitment and dispatch in accordance with the terms of the Demand Reduction Offer. Demand Reduction Offers:

(i) Shall specify the Demand Response Resource and Blocks (price and demand reduction quantity pairs) for each hour of the Operating Day. The prices and demand reduction quantities may vary on an hourly basis.

(ii) Shall not specify a price that is above the Energy Offer Cap, below the Energy Offer Floor, or below the Demand Reduction Threshold Price in effect for the Operating Day. For purposes of clearing the Day-Ahead and Real-Time Energy Markets and calculating Day-Ahead and Real-Time Locational Marginal Prices and Real-Time Reserve Clearing Prices, any price specified below the Demand Reduction Threshold price in effect for the Operating Day will be considered to be equal to the Demand Reduction Threshold Price for the Operating Day.

(iii) Shall not include average avoided peak transmission or distribution losses in the demand reduction quantity.

(iv) May specify an Interruption Cost for each hour of the Operating Day, which may vary on an hourly basis.

(v) Shall specify a Minimum Reduction Time to be used for scheduling purposes that does not exceed 24 hours.

(vi) Shall specify a Maximum Reduction amount no greater than the sum of the Maximum Interruptible Capacities of the Demand Response Resource's operational Demand Response Assets.

(vii) Shall specify changes to the Maximum Reduction and Minimum Reduction from those submitted as part of the Demand Response Resource's Offer Data to reflect the physical operating characteristics and/or availability of the Demand Response Resource.

(f) **Demand Reduction Threshold Price –** The Demand Reduction Threshold Price for each month shall be determined through an analysis of a smoothed, historic supply curve for the month. The historic supply curve shall be derived from Real-Time generator and import Offer Data (excluding Coordinated External Transactions) for the same month of the previous year. The ISO may adjust the Offer Data to account for significant changes in generator and import availability or other significant changes to the historic supply curve. The historic supply curve shall be calculated as follows:

(a) Each generator and import offer Block (i.e., each price-quantity pair offered in the Real-Time Energy Market) for each day of the month shall be compiled and sorted in ascending order of price to create an unsmoothed supply curve.

(b) An unsmoothed supply curve for the month shall be formed from the price and cumulative quantity of each offer Block.

(c) A non-linear regression shall be performed on a sampled portion of the unsmoothed supply curve to produce an increasing, convex, smooth approximation of the supply curve.

(d) A historic threshold price P_{th} shall be determined as the point on the smoothed supply curve beyond which the benefit to load from the reduced LMP resulting from the demand reduction of Demand Response Resources exceeds the cost to load associated with compensating Demand Response Resources for demand reduction.

(e) The Demand Reduction Threshold Price for the upcoming month shall be determined by the following formula:

$$DRTP = P_{th} X — \frac{FPI_c}{FPI_h}$$

where FPI_h is the historic fuel price index for the same month of the previous year, and FPI_c is the fuel price index for the current month.

The historic and current fuel price indices used to establish the Demand Reduction Threshold Price for a month shall be based on the lesser of the monthly natural gas or heating oil fuel indices applicable to the New England Control Area, as calculated three business days before the start of the month preceding the Demand Reduction Threshold Price's effective date.

The ISO will post the Demand Reduction Threshold Price, along with the index-based fuel price values used in establishing the Demand Reduction Threshold Price, on its website by the 15th day of the month preceding the Demand Reduction Threshold Price's effective date.

(g) **Subsequent Operating Days** – Each Supply Offer, Demand Reduction Offer, or Demand Bid by a Market Participant of a Resource shall remain in effect for subsequent Operating Days until superseded or canceled except in the case of an External Transaction purchase, in which case, the Supply Offer shall remain in effect for the applicable Operating Day and shall not remain in effect for subsequent Operating Days. Hourly overrides of a Supply Offer, a Demand Reduction Offer, or a Demand Bid shall remain in effect only for the applicable Operating Day.

(h) **Load Estimate** – The ISO shall post on the internet the total hourly loads including Decrement Bids scheduled in the Day-Ahead Energy Market, as well as the ISO's estimate of the Control Area hourly load for the next Operating Day.

(i) **Prorated Supply** – In determining Day-Ahead schedules, in the event of multiple marginal Supply Offers, Demand Reduction Offers, Increment Offers and/or External Transaction purchases at a pricing location, the ISO shall clear the marginal Supply Offers, Demand Reduction Offers, Increment Offers and/or External Transaction purchases proportional to the amount of energy (MW) from each marginal offer and/or External Transaction at the pricing location. The Economic Maximum Limits, Economic Minimum Limits, Minimum Reductions and Maximum Reductions are not used in determining the amount of energy (MW) in each marginal Supply Offer or Demand Reduction Offer to be cleared on a pro-rated basis. However, the Day-Ahead schedules resulting from the pro-ration process will reflect Economic Maximum Limits, Economic Minimum Limits, Minimum Reductions and Maximum Reductions.

(j) **Prorated Demand** – In determining Day-Ahead schedules, in the event of multiple marginal Demand Bids, Decrement Bids and/or External Transaction sales at a pricing location, the ISO shall clear the marginal Demand Bids, Decrement Bids and/or External Transaction sales proportional to the amount of energy (MW) from each marginal bid and/or External Transaction at the pricing location.

(k) **Virtuals** – All Market Participants may submit Increment Offers and/or Decrement Bids that apply to the Day-Ahead Energy Market only. Such offers and bids must comply with the requirements set forth in the ISO New England Manuals and ISO New England Administrative Procedures and must specify amount, location and price, if any, at which the Market Participant desires to purchase or sell energy in the Day-Ahead Energy Market.

(l) **Energy Call Option Offers** – Market Participants selling into the New England Markets from Generator Assets or Demand Response Resources may submit Energy Call Option Offers for the following Operating Day. Energy Call Option Offers shall be submitted to the ISO in accordance with Section III.1.8.2 of this Market Rule 1.

III.1.10.2 Pool-Scheduled Resources.

Pool-Scheduled Resources are those Resources for which Market Participants submitted Supply Offers, Demand Reduction Offers, or Demand Bids in the Day-Ahead Energy Market and which the ISO scheduled in the Day-Ahead Energy Market as well as Generator Assets, DARDs or Demand Response Resources committed by the ISO subsequent to the Day-Ahead Energy Market. Such Resources shall be committed to provide or consume energy in the Real-Time dispatch unless the schedules for such Resources are revised pursuant to Sections III.1.10.9 or III.1.11. Pool-Scheduled Resources shall be governed by the following principles and procedures.

(a) Pool-Scheduled Resources shall be selected by the ISO on the basis of the prices offered for energy supply or consumption and related services, Start-Up Fees, No-Load Fees, Interruption Cost and the specified operating characteristics, offered by Market Participants.

(b) The ISO shall optimize the dispatch of energy, and commencing on June 1, 2024, energy and ancillary services, from Limited Energy Resources by request to minimize the as-bid production cost for the New England Control Area. In implementing the use of Limited Energy Resources, the ISO shall use its best efforts to select the most economic hours of operation for Limited Energy Resources, in order to make optimal use of such Resources in the Day-Ahead Energy Market consistent with the Supply Offers and Demand Reduction Offers of other Resources, the submitted Demand Bids and Decrement Bids, and ~~Operating Reserve and Replacement Reserve~~ ancillary services requirements procured pursuant to this Market Rule 1.

(c) Market Participants offering energy from facilities with fuel or environmental limitations may submit data to the ISO that is sufficient to enable the ISO to determine the available operating hours of such facilities.

(d) Market Participants shall make available their Pool-Scheduled Resources to the ISO for coordinated operation to supply the needs of the New England Control Area for energy and ancillary services.

III.1.10.3 Self-Scheduled Resources.

A Resource that is Self-Scheduled shall be governed by the following principles and procedures. The minimum duration of a Self-Schedule for a Generator Asset or DARD shall not result in the Generator Asset or DARD operating for less than its Minimum Run Time. A Generator Asset that is online as a result of a Self-Schedule will be dispatched above its Economic Minimum Limit based on the economic merit of its Supply Offer. A DARD that is consuming as a result of a Self-Schedule may be dispatched above its Minimum Consumption Limit based on the economic merit of its Demand Bid. A Demand Response Resource shall not be Self-Scheduled.

III.1.10.4 External Resources.

Market Participants with External Resources may submit External Transactions as detailed in Section III.1.10.7 and Section III.1.10.7.A of this Market Rule 1.

III.1.10.5 Dispatchable Asset Related Demand.

(a) External Transactions that are sales to an external Control Area are not eligible to be Dispatchable Asset Related Demands.

(b) A Market Participant with a Dispatchable Asset Related Demand in the New England Control Area must:

- (i) notify the ISO of any outage (including partial outages) that may reduce the Dispatchable Asset Related Demand's ability to respond to Dispatch Instructions and the expected return date from the outage;
- (ii) in accordance with the ISO New England Manuals and Operating Procedures, perform audit tests and submit the results to the ISO or provide to the ISO appropriate historical production data;
- (iii) abide by the ISO maintenance coordination procedures; and
- (iv) provide information reasonably requested by the ISO, including the name and location of the Dispatchable Asset Related Demand.

III.1.10.6 Electric Storage

A storage facility is a facility that is capable of receiving electricity from the grid and storing the energy for later injection of electricity back to the grid. A storage facility may participate in the New England Markets as described below.

(a) A storage facility that satisfies the requirements of this subsection (a) may participate in the New England Markets as an Electric Storage Facility. An Electric Storage Facility shall:

- (i) comprise one or more storage facilities at the same point of interconnection;
- (ii) have the ability to inject at least 0.1 MW and consume at least 0.1 MW;
- (iii) be directly metered;
- (iv) be registered as, and subject to all rules applicable to, a dispatchable Generator Asset;
- (v) be registered as, and subject to all rules applicable to, a DARD that represents the same equipment as the Generator Asset;
- (vi) settle its injection of electricity to the grid as a Generator Asset and its receipt of electricity from the grid as a DARD;
- (vii) not be precluded from providing retail services so long as it is able to fulfill its wholesale Energy Market and Forward Capacity Market obligations including, but not limited to, satisfying meter data reporting requirements and notifying the ISO of any changes to operational capabilities; and
- (viii) meet the requirements of either a Binary Storage Facility or a Continuous Storage Facility, as described in subsections (b) and (c) below.

(b) A storage facility that satisfies the requirements of this subsection (b) may participate in the New England Markets as a Binary Storage Facility. A Binary Storage Facility shall:

(i) satisfy the requirements applicable to an Electric Storage Facility; and

(ii) offer its Generator Asset and DARD into the Energy Market as Rapid Response Pricing Assets; and

(iii) be issued Dispatch Instructions in a manner that ensures the facility is not required to consume and inject simultaneously.

(c) A storage facility that satisfies the requirements of this subsection (c) may participate in the New England Markets as a Continuous Storage Facility. A Continuous Storage Facility shall:

(i) satisfy the requirements applicable to an Electric Storage Facility;

(ii) be registered as, may provide Regulation as, and is subject to all rules applicable to, an ATRR that represents the same equipment as the Generator Asset and DARD;

(iii) be capable of transitioning between the facility's maximum output and maximum consumption (and vice versa) in ten minutes or less;

(iv) not utilize storage capability that is shared with another Generator Asset, DARD or ATRR;

(v) specify in Supply Offers a zero MW value for Economic Minimum Limit and Emergency Minimum Limit (except for Generator Assets undergoing Facility and Equipment Testing or auditing); a zero time value for Minimum Run Time, Minimum Down Time, Notification Time, and Start-Up Time; and a zero cost value for Start-Up Fee and No-Load Fee;

(vi) specify in Demand Bids a zero MW value for Minimum Consumption Limit (except for DARDs undergoing Facility and Equipment Testing or auditing) and a zero time value for Minimum Run Time and Minimum Down Time;

(vii) be Self-Scheduled in the Day-Ahead Energy Market and Real-Time Energy Market, and operate in an on-line state, unless the facility is declared unavailable by the Market Participant; and

(viii) be issued a combined dispatch control signal equal to the Desired Dispatch Point (of the Generator Asset) minus the Desired Dispatch Point (of the DARD) plus the AGC SetPoint (of the ATRR).

(d) A storage facility shall comply with all applicable registration, metering, and accounting rules including, but not limited to, the following:

(i) A Market Participant wishing to purchase energy from the ISO-administered wholesale markets must first, jointly with its Host Participant, register one or more wholesale Load Assets with the ISO as described in ISO New England Manual M-28 and ISO New England Manual M-RPA; where the Market Participant wishes to register an Electric Storage Facility, the registered Load Asset must be a DARD.

(ii) A storage facility's charging load shall not qualify as a DARD if the Host Participant is unwilling or unable to support the registration, metering, and accounting of the storage facility's load as a separate and distinct Load Asset. A storage facility registered as a DARD will be charged the nodal Locational Marginal Price by the ISO and the Market Participant will not pay twice for the same charging load.

(iii) The registration and metering of all Assets must comply with ISO New England Operating Procedure No. 14 and ISO New England Operating Procedure No. 18, including with the requirement that an Asset's revenue metering must comply with the accuracy requirements found in ISO New England Operating Procedure No. 18.

(iv) Pursuant to ISO New England Manual M-28, the Assigned Meter Reader, the Host Participant, and the ISO provide the data for use in the daily settlement process within the timelines described in the manual. The data may be five-minute interval data, and may be no more than hourly data, as described in Section III.3.2 and in ISO New England Manual M-28.

(v) Based on the Metered Quantity For Settlement and the Locational Marginal Price in the settlement interval, the ISO shall conduct all Energy Market accounting pursuant to Section III.3.2.1.

(e) A facility registered as a dispatchable Generator Asset, an ATRR, and a DARD that each represent the same equipment must participate as a Continuous Storage Facility.

(f) A storage facility not participating as an Electric Storage Facility may, if it satisfies the associated requirements, be registered as a Generator Asset (including a Settlement Only Resource) for settlement of its injection of electricity to the grid and as an Asset Related Demand for settlement of its wholesale load.

(g) A storage facility may, if it satisfies the associated requirements, be registered as a Demand Response Asset. (As described in Section III.8.1.1, a Demand Response Asset and a Generator Asset may not be registered at the same end-use customer facility unless the Generator Asset is separately metered and reported and its output does not reduce the load reported at the Retail Delivery Point of the Demand Response Asset.)

(h) A storage device may, if it satisfies the associated requirements, be registered as a component of either an On-Peak Demand Resource or a Seasonal Peak Demand Resource.

(i) A storage facility may, if it satisfies the associated requirements, provide Regulation pursuant to Section III.14.

III.1.10.7 External Transactions.

The provisions of this Section III.1.10.7 do not apply to Coordinated External Transactions.

(a) Market Participants that submit an External Transaction in the Day-Ahead Energy Market must also submit a corresponding External Transaction in the Real-Time Energy Market in order to be eligible for scheduling in the Real-Time Energy Market. Priced External Transactions for the Real-Time Energy Market must be submitted by the offer submission deadline for the Day-Ahead Energy Market.

(b) Priced External Transactions submitted in both the Day-Ahead Energy Market and the Real-Time Energy Market will be treated as Self-Scheduled External Transactions in the Real-Time Energy Market for the associated megawatt amounts that cleared the Day-Ahead Energy Market, unless the Market Participant modifies the price component of its Real-Time offer during the Re-Offer Period.

(c) Any External Transaction, or portion thereof, submitted to the Real-Time Energy Market that did not clear in the Day-Ahead Energy Market will not be scheduled in Real-Time if the ISO anticipates that the External Transaction would create or worsen an Emergency. External Transactions cleared in the Day-Ahead Energy Market and associated with a Real-Time Energy Market submission will continue to be scheduled in Real-Time prior to and during an Emergency, until the procedures governing the Emergency, as set forth in ISO New England Operating Procedure No. 9, require a change in schedule.

(d) External Transactions submitted to the Real-Time Energy Market must contain the associated e-Tag ID and transmission reservation, if required, at the time the transaction is submitted to the Real-Time Energy Market.

(e) [Reserved.]

(f) External Transaction sales meeting all of the criteria for any of the transaction types described in (i) through (iv) below receive priority in the scheduling and curtailment of transactions as set forth in Section II.44 of the OATT. External Transaction sales meeting all of the criteria for any of the transaction types described in (i) through (iv) below are referred to herein and in the OATT as being supported in Real-Time.

(i) Capacity Export Through Import Constrained Zone Transactions:

(1) The External Transaction is exporting across an external interface located in an import-constrained Capacity Zone that cleared in the Forward Capacity Auction with price separation, as determined in accordance with Section III.12.4 and Section III.13.2.3.4 of Market Rule 1;

(2) The External Transaction is directly associated with an Export Bid or Administrative Export De-List Bid that cleared in the Forward Capacity Auction, and the megawatt amount of the External Transaction is less than or equal to the megawatt amount of the cleared Export Bid;

(3) The External Node associated with the cleared Export Bid or Administrative Export De-List Bid is connected to the import-constrained Capacity Zone, and is not connected to a Capacity Zone that is not import-constrained;

(4) The Resource, or portion thereof, that is associated with the cleared Export Bid or Administrative Export De-List Bid is not located in the import-constrained Capacity Zone;

(5) The External Transaction has been submitted and cleared in the Day-Ahead Energy Market;

(6) A matching External Transaction has also been submitted into the Real-Time Energy Market by the end of the Re-Offer Period for Self-Scheduled External Transactions, and, in accordance with Section III.1.10.7(a), by the offer submission deadline for the Day-Ahead Energy Market for priced External Transactions.

(ii) FCA Cleared Export Transactions:

(1) The External Transaction sale is exporting to an External Node that is connected only to an import-constrained Reserve Zone;

(2) The External Transaction sale is directly associated with an Export Bid or an Administrative Export De-List Bid that cleared in the Forward Capacity Auction, and the megawatt amount of the External Transaction is less than or equal to the megawatt amount of the cleared Export Bid;

(3) The Resource, or portion thereof, without a Capacity Supply Obligation associated with the Export Bid or Administrative Export De-List Bid is located outside the import-constrained Reserve Zone;

(4) The External Transaction sale is submitted and cleared in the Day-Ahead Energy Market;

(5) A matching External Transaction has also been submitted into the Real-Time Energy Market by the end of the Re-Offer Period for Self-Scheduled External Transactions, and, in accordance with Section III.1.10.7(a), by the offer submission deadline for the Day-Ahead Energy Market for priced External Transactions.

(iii) Same Reserve Zone Export Transactions:

(1) A Resource, or portion thereof, without a Capacity Supply Obligation is associated with the External Transaction sale, and the megawatt amount of the External Transaction is less than or equal to the portion of the Resource without a Capacity Supply Obligation;

(2) The External Node of the External Transaction sale is connected only to the same Reserve Zone in which the associated Resource, or portion thereof, without a Capacity Supply Obligation is located;

(3) The Resource, or portion thereof, without a Capacity Supply Obligation is Self-Scheduled in the Real-Time Energy Market and online at a megawatt level greater than or equal to the External Transaction sale’s megawatt amount;

(4) Neither the External Transaction sale nor the portion of the Resource without a Capacity Supply Obligation is required to offer into the Day-Ahead Energy Market.

(iv) Unconstrained Export Transactions:

(1) A Resource, or portion thereof, without a Capacity Supply Obligation is associated with the External Transaction sale, and the megawatt amount of the External Transaction is less than or equal to the portion of the Resource without a Capacity Supply Obligation;

(2) The External Node of the External Transaction sale is not connected only to an import-constrained Reserve Zone;

(3) The Resource, or portion thereof, without a Capacity Supply Obligation is not separated from the External Node by a transmission interface constraint as determined in Sections III.12.2.1(b) and III.12.2.2(b) of Market Rule 1 that was binding in the Forward Capacity Auction in the direction of the export;

(4) The Resource, or portion thereof, without a Capacity Supply Obligation is Self-Scheduled in the Real-Time Energy Market and online at a megawatt level greater than or equal to the External Transaction sale’s megawatt amount;

(5) Neither the External Transaction sale, nor the portion of the Resource without a Capacity Supply Obligation is required to offer into the Day-Ahead Energy Market.

(g) Treatment of External Transaction sales in ISO commitment for local second contingency protection.

(i) Capacity Export Through Import Constrained Zone Transactions and FCA Cleared Export Transactions: The transaction’s export demand that clears in the Day-Ahead Energy Market will be explicitly considered as load in the exporting Reserve Zone by the ISO when committing Resources to provide local second contingency protection for the associated Operating Day.

(ii) The export demand of External Transaction sales not meeting the criteria in (i) above is not considered by the ISO when planning and committing Resources to provide local second contingency protection, and is assumed to be zero.

(iii) Same Reserve Zone Export Transactions and Unconstrained Export Transactions: If a Resource, or portion thereof, without a Capacity Supply Obligation is committed to be online during the Operating Day either through clearing in the Day-Ahead Energy Market or through Self-Scheduling subsequent to the Day-Ahead Energy Market and a Same Reserve Zone Export Transaction or Unconstrained Export Transaction is submitted before the end of the Re-Offer Period designating that Resource as supporting the transaction, the ISO will not utilize the portion of the Resource without a Capacity Supply Obligation supporting the export transaction to meet local second contingency protection requirements. The eligibility of Resources not meeting the foregoing criteria to be used to meet local second contingency protection requirements shall be in accordance with the relevant provisions of the ISO New England System Rules.

(h) Allocation of costs to Capacity Export Through Import Constrained Zone Transactions and FCA Cleared Export Transactions: Market Participants with Capacity Export Through Import Constrained Zone Transactions and FCA Cleared Export Transactions shall incur a proportional share of the charges described below, which are allocated to Market Participants based on Day-Ahead Load Obligation or Real-Time Load Obligation. The share shall be determined by including the Day-Ahead Load Obligation or Real-Time Load Obligation associated with the External Transaction, as applicable, in the total Day-Ahead Load Obligation or Real-Time Load Obligation for the appropriate Reliability Region, Reserve Zone, or Load Zone used in each cost allocation calculation:

(i) NCPC for Local Second Contingency Protection Resources allocated within the exporting Reliability Region, pursuant to Section III.F.3.3.

(ii) Forward Reserve Market charges allocated within the exporting Load Zone, pursuant to Section III.9.9.

(iii) Real-Time Reserve Charges allocated within the exporting Load Zone, pursuant to Section III.10.3.

(i) When action is taken by the ISO to reduce External Transaction sales due to a system wide capacity deficient condition or the forecast of such a condition, and an External Transaction sale designates a Resource, or portion of a Resource, without a Capacity Supply Obligation, to support the transaction, the ISO will review the status of the designated Resource. If the designated Resource is Self-Scheduled and online at a megawatt level greater than or equal to the External Transaction sale, that External Transaction sale will not be reduced until such time as Regional Network Load within the New England Control Area is also being reduced. When reductions to such transactions are required, the affected transactions shall be reduced pro-rata.

(j) Market Participants shall submit External Transactions as megawatt blocks with intervals of one hour at the relevant External Node. External Transactions will be scheduled in the Day-Ahead Energy Market as megawatt blocks for hourly durations. The ISO may dispatch External Transactions in the Real-Time Energy Market as megawatt blocks for periods of less than one hour, to the extent allowed pursuant to inter-Control Area operating protocols.

III.1.10.7.A Coordinated Transaction Scheduling.

The provisions of this Section III.1.10.7.A apply to Coordinated External Transactions, which are implemented at the New York Northern AC external Location.

(a) Market Participants that submit a Coordinated External Transaction in the Day-Ahead Energy Market must also submit a corresponding Coordinated External Transaction, in the form of an Interface Bid, in the Real-Time Energy Market in order to be eligible for scheduling in the Real-Time Energy Market.

(b) An Interface Bid submitted in the Real-Time Energy Market shall specify a duration consisting of one or more consecutive 15-minute increments. An Interface Bid shall include a bid price, a bid quantity, and a bid direction for each 15-minute increment. The bid price may be positive or negative. An Interface Bid may not be submitted or modified later than 75 minutes before the start of the clock hour for which it is offered.

(c) Interface Bids are cleared in economic merit order for each 15-minute increment, based upon the forecasted real-time price difference across the external interface. The total quantity of Interface Bids cleared shall determine the external interface schedule between New England and the adjacent Control Area. The total quantity of Interface Bids cleared shall depend upon, among other factors, bid production costs of resources in both Control Areas, the Interface Bids of all Market Participants, transmission system conditions, and any real-time operating limits necessary to ensure reliable operation of the transmission system.

(d) All Coordinated External Transactions submitted either to the Day-Ahead Energy Market or the Real-Time Energy Market must contain the associated e-Tag ID at the time the transaction is submitted.

(e) Any Coordinated External Transaction, or portion thereof, submitted to the Real-Time Energy Market will not be scheduled in Real-Time if the ISO anticipates that the External Transaction would create or worsen an Emergency, unless the procedures governing the Emergency, as set forth in ISO New England Operating Procedure No. 9, permit the transaction to be scheduled.

III.1.10.8 ISO Responsibilities.

(a) Scheduling Considerations

(i) Prior to June 1, 2024, t~~T~~he ISO shall use its best efforts to determine (~~i~~1) the least-cost means of satisfying hourly purchase requests for energy, the projected hourly requirements for Operating Reserve, Replacement Reserve and other ancillary services of the Market Participants, including the reliability requirements of the New England Control Area, of the Day-Ahead Energy Market, and (~~ii~~2) the least-cost means of satisfying the Operating Reserve, Replacement Reserve and other ancillary service requirements for any portion of the load forecast of the ISO for the Operating Day in excess of that scheduled in the Day-Ahead Energy Market.

In making the~~se~~ determinations specified in this subsection (a)(i), the ISO shall take into account: (i) the ISO's forecasts of New England Markets and New England Control Area energy requirements, giving due consideration to the energy requirement forecasts and purchase requests submitted by Market Participants for the Day-Ahead Energy Market; (ii) the offers and bids submitted by Market Participants; (iii) the availability of Limited Energy Resources; (iv) the capacity, location, and other relevant characteristics of Self-Scheduled Resources; (v) the requirements of the New England Control Area for Operating Reserve and Replacement Reserve, as specified in the ISO New England Manuals and ISO New England Administrative Procedures; (vi) the requirements of the New England Control Area for Regulation and other ancillary services, as specified in the ISO New England Manuals and ISO New England Administrative Procedures; (vii) the benefits of avoiding or minimizing transmission constraint control operations, as specified in the ISO New England Manuals and ISO New England Administrative Procedures; and (viii) such other factors as the ISO reasonably concludes are relevant to the foregoing determination. The ISO shall develop a Day-Ahead Energy schedule based on the applicable portions of the foregoing determination, and shall determine the Day-Ahead Prices resulting from such schedule.

(ii) Commencing on June 1, 2024, in scheduling the Day-Ahead Energy Market, the ISO shall use its best efforts to determine the security-constrained economic commitment and dispatch that jointly optimizes: (1) Demand Bids, Decrement Bids, Demand Reduction Offers, Supply Offers, Increment Offers, and External Transactions, for energy; (2) Energy Call Option Offers to satisfy the Day-Ahead Ancillary Services demand quantities; and (3) Supply Offers, Demand Reduction Offers, External Transactions, and Energy Call Option Offers to satisfy the Forecast Energy Requirement Demand Quantity.

In making the determinations specified in this subsection (a)(ii), the ISO shall take into account, as applicable: (1) the ISO's forecasts of New England Markets and New England Control Area energy requirements, giving due consideration to the energy requirement forecasts and purchase requests submitted by Market Participants for the Day-Ahead Energy Market; (2) the offers and bids submitted by Market Participants; (3) the availability of Limited Energy Resources; (4) capacity, location, and other relevant characteristics of Self-Scheduled Resources; (5) the requirements of the New England Control Area for ancillary services; (6) the operational capabilities of any Resource to adjust the output, consumption, or demand reduction within the operating characteristics specified in the Market Participant's Offer Data, Supply Offer, Demand Reduction Offer, or Demand Bid; (7) the benefits of avoiding or minimizing transmission constraint control operations, as specified in the ISO New England Manuals and ISO New England Administrative Procedures; and (8) such other factors as the ISO reasonably concludes are relevant to the foregoing determination.

In scheduling the Day-Ahead Energy Market, the following limitations shall apply:

(1) For purposes of satisfying the demand quantities for Day-Ahead Generation Contingency Reserve or Day-Ahead Replacement Energy Reserve specified in Sections III.1.8.5(a)-(e), the ISO shall not take into account an Energy Call Option Offer unless the Generator Asset or the Demand Response Resource associated with the Energy Call Option Offer meets the eligibility requirements enumerated in Section III.1.7.19.1.

(2) For purposes of satisfying the Day-Ahead Energy Imbalance Reserve Demand Quantity specified in Section III.1.8.5(f), the ISO shall not take into account an Energy Call

Option Offer unless the Generator Asset or the Demand Response Resource associated with the Energy Call Option Offer is either (i) scheduled for energy in the Day-Ahead Energy Market for the applicable hour, or (ii) is a Fast Start Generator or Fast Start Demand Response Resource.

(b) Not later than 1:30 p.m. of the day before each Operating Day, or such earlier deadline as may be specified by the ISO in the ISO New England Manuals and ISO New England Administrative Procedures or such later deadline as necessary to account for software failures or other events, the ISO shall: (i) post the aggregate Day-Ahead Energy schedule; (ii) post the Day-Ahead Prices; and (iii) inform the Market Participants of their scheduled injections and withdrawals. In the event of an Emergency, the ISO will notify Market Participants as soon as practicable if the Day-Ahead Energy Market can-not be operated.

(c) Following posting of the information specified in Section III.1.10.8(b), the ISO shall revise its schedule of Resources to reflect updated projections of load, conditions affecting electric system operations in the New England Control Area, the availability of and constraints on limited energy and other Resources, transmission constraints, and other relevant factors. The ISO shall use its best efforts to determine the least-cost means to satisfy any remaining reliability requirements of the New England Control Area for the Operating Day.

(d) Market Participants shall pay and be paid for the quantities of energy scheduled in the Day-Ahead Energy Market at the applicable Day-Ahead Prices.

III.1.10.9 Hourly Scheduling.

(a) Following the initial posting by the ISO of the Locational Marginal Prices resulting from the Day-Ahead Energy Market, and subject to the right of the ISO to schedule and dispatch Resources and to direct that schedules be changed to address an actual or potential Emergency, a Resource Re-Offer Period shall exist from the time of the posting specified in Section III.1.10.8(b) until 2:00 p.m. on the day before each Operating Day or such other Re-Offer Period as necessary to account for software failures or other events. During the Re-Offer Period, Market Participants may submit revisions to Supply Offers, revisions to Demand Reduction Offers, and revisions to Demand Bids for any Dispatchable Asset Related Demand. Resources scheduled subsequent to the closing of the Re-Offer Period shall be settled at the applicable Real-Time Prices, and shall not affect the obligation to pay or receive payment for the quantities of energy scheduled in the Day-Ahead Energy Market at the applicable Day-Ahead Prices.

(b) During the Re-Offer Period, Market Participants may submit revisions to the price of priced External Transactions. External Transactions scheduled subsequent to the closing of the Re-Offer Period shall be settled at the applicable Real-Time Prices, and shall not affect the obligation to pay or receive payment for the quantities of energy scheduled in the Day-Ahead Energy Market at the applicable Day-Ahead Prices. A submission during the Re-Offer Period for any portion of a transaction that was cleared in the Day-Ahead Energy Market is subject to the provisions in Section III.1.10.7. A Market Participant may request to Self-Schedule an External Transaction and adjust the schedule on an hour-to-hour basis or request to reduce the quantity of a priced External Transaction. The ISO must be notified of the request not later than 60 minutes prior to the hour in which the adjustment is to take effect. The External Transaction re-offer provisions of this Section III.1.10.9(b) shall not apply to Coordinated External Transactions, which are submitted pursuant to Section III.1.10.7.A.

(c) Following the completion of the initial Reserve Adequacy Analysis and throughout the Operating Day, a Market Participant may modify certain Supply Offer or Demand Bid parameters for a Generator Asset or a Dispatchable Asset Related Demand on an hour-to-hour basis, provided that the modification is made no later than 30 minutes prior to the beginning of the hour for which the modification is to take effect:

- (i) For a Generator Asset, the Start-Up Fee, the No-Load Fee, the fuel type (for dual-fuel Generator Assets), and the quantity and price pairs of its Blocks may be modified.
- (ii) For a Dispatchable Asset Related Demand, the quantity and price pairs of its Blocks may be modified.

(d) Following the completion of the initial Reserve Adequacy Analysis and throughout the Operating Day, a Market Participant may not modify any of the following Demand Reduction Offer parameters: price and demand reduction quantity pairs, Interruption Cost, Demand Response Resource Start-Up Time, Demand Response Resource Notification Time, Minimum Reduction Time, and Minimum Time Between Reductions.

(e) During the Operating Day, a Market Participant may request to Self-Schedule a Generator Asset or Dispatchable Asset Related Demand or may request to cancel a Self-Schedule for a Generator Asset or Dispatchable Asset Related Demand. The ISO will honor the request so long as it will not cause or worsen a reliability constraint. If the ISO is able to honor a Self-Schedule request, a Generator Asset will be permitted to come online at its Economic Minimum Limit and a Dispatchable Asset Related Demand will be dispatched to its Minimum Consumption Limit. A Market Participant may not request to Self-

Schedule a Demand Response Resource. A Market Participant may cancel the Self-Schedule of a Continuous Storage Generator Asset or a Continuous Storage DARD only by declaring the facility unavailable.

(f) During the Operating Day, in the event that in a given hour a Market Participant seeks to modify a Supply Offer or Demand Bid after the deadline for modifications specified in Section III.1.10.9(c), then:

(i) the Market Participant may request that a Generator Asset be dispatched above its Economic Minimum Limit at a specified output. The ISO will honor the request so long as it will not cause or worsen a reliability constraint. If the ISO is able to honor the request, the Generator Asset will be dispatched as though it had offered the specified output for the hour in question at the Energy Offer Floor.

(ii) the Market Participant may request that a Dispatchable Asset Related Demand be dispatched above its Minimum Consumption Limit at a specified value. The ISO will honor the request so long as it will not cause or worsen a reliability constraint. If the ISO is able to honor the request, the Dispatchable Asset Related Demand will be dispatched at or above the requested amount for the hour in question.

(g) During the Operating Day, in any interval in which a Generator Asset is providing Regulation, the upper limit of its energy dispatch range shall be reduced by the amount of Regulation Capacity, and the lower limit of its energy dispatch range shall be increased by the amount of Regulation Capacity. Any such adjustment shall not affect the Real-Time Reserve Designation.

(h) During the Operating Day, in any interval in which a Continuous Storage ATRR is providing Regulation, the upper limit of the associated Generator Asset's energy dispatch range shall be reduced by the Regulation High Limit, and the associated DARD's consumption dispatch range shall be reduced by the Regulation Low Limit. Any such adjustment shall not affect the Real-Time Reserve Designation.

(i) For each hour in the Operating Day, as soon as practicable after the deadlines specified in the foregoing subsection of this Section III.1.10, the ISO shall provide Market Participants and parties to External Transactions with any revisions to their schedules for the hour.

III.1.11 Dispatch.

The following procedures and principles shall govern the dispatch of the Resources available to the ISO.

III.1.11.1 Resource Output or Consumption and Demand Reduction.

The ISO shall have the authority to direct any Market Participant to adjust the output, consumption or demand reduction of any Dispatchable Resource within the operating characteristics specified in the Market Participant's Offer Data, Supply Offer, Demand Reduction Offer or Demand Bid. The ISO may cancel its selection of, or otherwise release, Pool-Scheduled Resources. The ISO shall adjust the output, consumption or demand reduction of Resources as necessary: (a) for both Dispatchable Resources and Non-Dispatchable Resources, to maintain reliability, and subject to that constraint, for Dispatchable Resources, (b) to minimize the cost of supplying the energy, reserves, and other services required by the Market Participants and the operation of the New England Control Area; (c) to balance supply and demand, maintain scheduled tie flows, and provide frequency support within the New England Control Area; and (d) to minimize unscheduled interchange that is not frequency related between the New England Control Area and other Control Areas.

III.1.11.2 Operating Basis.

In carrying out the foregoing objectives, the ISO shall conduct the operation of the New England Control Area and shall, in accordance with the ISO New England Manuals and ISO New England Administrative Procedures, (i) utilize available Operating Reserve and replace such Operating Reserve when utilized; and (ii) monitor the availability of adequate Operating Reserve.

III.1.11.3 Dispatchable Resources.

With the exception of Settlement Only Resources, Generator Assets that meet the size criteria to be Settlement Only Resources, External Transactions, nuclear-powered Resources and photovoltaic Resources, all Resources must be Dispatchable Resources in the Energy Market and meet the technical specifications in ISO New England Operating Procedure No. 14 and ISO New England Operating Procedure No. 18 for dispatchability.

A Market Participant that does not meet the requirement for a Dispatchable Resource to be dispatchable in the Energy Market because the Resource is not connected to a remote terminal unit meeting the requirements of ISO New England Operating Procedure No. 18 shall take the following steps:

1. By January 15, 2017, the Market Participant shall submit to the ISO a circuit order form for the primary and secondary communication paths for the remote terminal unit.

2. The Market Participant shall work diligently with the ISO to ensure the Resource is able to receive and respond to electronic Dispatch Instructions within twelve months of the circuit order form submission.

A Market Participant that does not meet the requirement for a Dispatchable Resource to be dispatchable in the Energy Market by the deadline set forth above shall provide the ISO with a written plan for remedying the deficiencies, and shall identify in the plan the specific actions to be taken and a reasonable timeline for rendering the Resource dispatchable. The Market Participant shall complete the remediation in accordance with and under the timeline set forth in the written plan. Until a Resource is dispatchable, it may only be Self-Scheduled in the Real-Time Energy Market and shall otherwise be treated as a Non-Dispatchable Resource.

Dispatchable Resources in the Energy Market are subject to the following requirements:

(a) The ISO shall optimize the dispatch of energy from Limited Energy Resources by request to minimize the as-bid production cost for the New England Control Area. In implementing the use of Limited Energy Resources, the ISO shall use its best efforts to select the most economic hours of operation for Limited Energy Resources, in order to make optimal use of such Resources consistent with the dynamic load-following requirements of the New England Control Area and the availability of other Resources to the ISO.

(b) The ISO shall implement the dispatch of energy from Dispatchable Resources and the designation of Real-Time Operating Reserve to Dispatchable Resources, including the dispatchable portion of Resources which are otherwise Self-Scheduled, by sending appropriate signals and instructions to the entity controlling such Resources. Each Market Participant shall ensure that the entity controlling a Dispatchable Resource offered or made available by that Market Participant complies with the energy dispatch signals and instructions transmitted by the ISO.

(c) The ISO shall have the authority to modify a Market Participant's operational related Offer Data for a Dispatchable Resource if the ISO observes that the Market Participant's Resource is not operating in accordance with such Offer Data. The ISO shall modify such operational related Offer Data based on observed performance and such modified Offer Data shall remain in effect until either (i) the affected Market Participant requests a test to be performed, and coordinates the testing pursuant to the procedures specified in the ISO New England Manuals, and the results of the test justify a change to the Market Participant's Offer Data or (ii) the ISO observes, through actual performance, that modification to the Market Participant's Offer Data is justified.

(d) Market Participants shall exert all reasonable efforts to operate, or ensure the operation of, their Dispatchable Resources in the New England Control Area as close to dispatched output, consumption or demand reduction levels as practical, consistent with Good Utility Practice.

(e) Settlement Only Resources are not eligible to be DNE Dispatchable Generators.

Wind and hydro Intermittent Power Resources that are not Settlement Only Resources are required to receive and respond to Do Not Exceed Dispatch Points, except as follows:

(i) A wind or hydro Intermittent Power Resource not capable of receiving and responding to electronic Dispatch Instructions will be manually dispatched.

(ii) A Market Participant may elect, but is not required, to have a wind or hydro Intermittent Power Resource that is less than 5 MW and is connected through transmission facilities rated at less than 115 kV be dispatched as a DNE Dispatchable Generator.

(iii) A Market Participant with a hydro Intermittent Power Resource that is able to operate within a dispatchable range and is capable of responding to Dispatch Instructions to increase or decrease output within its dispatchable range may elect to have that resource dispatched as a DDP Dispatchable Resource.

(f) The ISO may request that dual-fuel Generator Assets that normally burn natural gas voluntarily take all necessary steps (within the limitations imposed by the operating limitations of their installed equipment and their environmental and operating permits) to prepare to switch to secondary fuel in anticipation of natural gas supply shortages. The ISO may request that Market Participants with dual-fuel Generator Assets that normally burn natural gas voluntarily switch to a secondary fuel in anticipation of natural gas supply shortages. The ISO may communicate with Market Participants with dual-fuel Generator Assets that normally burn natural gas to verify whether the Market Participants have switched or are planning to switch to an alternate fuel.

III.1.11.4 Emergency Condition.

If the ISO anticipates or declares an Emergency Condition, all External Transaction sales out of the New England Control Area that are not backed by a Resource may be interrupted, in accordance with the ISO New England Manuals, in order to serve load and Operating Reserve in the New England Control Area.

III.1.11.5 Dispatchability Requirements for Intermittent Power Resources.

(a) Intermittent Power Resources that are Dispatchable Resources with Supply Offers that do not clear in the Day-Ahead Energy Market and are not committed by the ISO prior to or during the Operating Day must be Self-Scheduled in the Real-Time Energy Market at the Resource's Economic Minimum Limit in order to operate in Real-Time.

(b) Intermittent Power Resources that are not Settlement Only Resources, are not Dispatchable Resources, and are not committed by the ISO prior to or during the Operating Day must be Self-Scheduled in the Real-Time Energy Market with the Resource's Economic Maximum Limit and Economic Minimum Limit redeclared to the same value in order to operate in Real-Time. Redeclarations must be updated throughout the Operating Day to reflect actual operating capabilities.

III.1.11.6 Non-Dispatchable Resources.

Non-Dispatchable Resources are subject to the following requirements:

(a) The ISO shall have the authority to modify a Market Participant's operational related Offer Data for a Non-Dispatchable Resource if the ISO observes that the Market Participant's Resource is not operating in accordance with such Offer Data. The ISO shall modify such operational related Offer Data based on observed performance and such modified Offer Data shall remain in effect until either (i) the affected Market Participant requests a test to be performed and coordinates the testing pursuant to the procedures specified in the ISO New England Manuals, and the results of the test justify a change to the Market Participant's Offer Data or (ii) the ISO observes, through actual performance, that modification to the Market Participant's Offer Data is justified.

(b) Market Participants with Non-Dispatchable Resources shall exert all reasonable efforts to operate or ensure the operation of their Resources in the New England Control Area as close to dispatched levels as practical when dispatched by the ISO for reliability, consistent with Good Utility Practice.

III.2 Day-Ahead Prices, Real-Time Prices, ~~LMPs~~ and Real-Time Reserve Clearing Prices Calculation

III.2.1 Introduction.

The ISO shall calculate the price of energy at Nodes, Load Zones, DRR Aggregation Zones and Hubs in the New England Control Area and at External Nodes on the basis of Locational Marginal Prices and shall calculate the price of Operating Reserve in Real-Time for each Reserve Zone on the basis of Real-Time Reserve Clearing Prices as determined in accordance with this Market Rule 1. Locational Marginal Prices for energy shall be calculated on a Day-Ahead basis for each hour of the Day-Ahead Energy Market, and every five minutes during the Operating Day for the Real-Time Energy Market. Real-Time Reserve Clearing Prices shall be calculated on a Real-Time basis every five minutes as part of the joint optimization of energy and Operating Reserve during the Operating Day. Commencing on June 1, 2024, Day-Ahead Ancillary Services prices and the Forecast Energy Requirement Price shall be calculated for each hour of the Operating Day, as specified in Section III.2.6.2, as part of the joint optimization of energy and ancillary services in the Day-Ahead Energy Market.

III.2.2 General.

The ISO shall determine the least cost security-constrained unit commitment and dispatch, which is the least costly means of serving load at different Locations in the New England Control Area based on scheduled or actual conditions, as applicable, existing on the power grid and on the prices at which Market Participants have offered to supply and consume energy in the New England Markets. Day-Ahead Locational Marginal Prices for energy for the applicable Locations will be calculated based on the unit commitment and economic dispatch and the prices of ~~energy~~ offers and bids. Real-Time Locational Marginal Prices for energy and Real-Time Reserve Clearing Prices will be calculated based on a jointly optimized economic dispatch of energy and designation of Operating Reserve utilizing the prices of energy offers and bids, and Reserve Constraint Penalty Factors as specified in Section III.2.7A when applicable. Commencing on June 1, 2024, Day-Ahead Locational Marginal Prices for energy, Day-Ahead Ancillary Services prices, and the Forecast Energy Requirement Price will be calculated based on a jointly optimized security-constrained economic commitment and dispatch of energy and Day-Ahead Ancillary Services utilizing the prices of offers and bids, and Reserve Constraint Penalty Factors as specified in Section III.2.6.2(b) when applicable.

Except as further provided in Section III.2.6, the process for the determination of Locational Marginal Prices shall be as follows:

(a) To determine operating conditions, in the Day-Ahead Energy Market or Real-Time Energy Market, on the New England Transmission System, the ISO shall use a computer model of the interconnected grid that uses scheduled quantities or available metered inputs regarding electric output, loads, and power flows to model remaining flows and conditions, producing a consistent representation of power flows on the network. The computer model employed for this purpose in the Real-Time Energy Market, referred to as the State Estimator program, is a standard industry tool and is described in Section III.2.3. It will be used to obtain information regarding the output of resources supplying energy and Operating Reserve to the New England Control Area, loads at busses in the New England Control Area, transmission losses, penalty factors, and power flows on binding transmission and interface constraints for use in the calculation of Day-Ahead and Real-Time Locational Marginal Prices and Real-Time Reserve Clearing Prices, and, commencing on June 1, 2024, Day-Ahead Ancillary Services prices and the Forecast Energy Requirement Price. Additional information used in the calculation of Real-Time Locational Marginal Prices and Real-Time Reserve Clearing Prices, including Offer Data, Real-Time Operating Reserve designations and Real-Time schedules for External Transactions, will be obtained from the ISO's dispatch software and dispatchers.

(b) Using the prices at which Market Participants offer and bid energy to the New England Markets, the ISO shall determine the offers and bids of energy that will be considered in the calculation of Day-Ahead Prices, Real-Time Prices and Real-Time Reserve Clearing Prices. During the Operating Day, Real-Time nodal Locational Marginal Prices and Real-Time Reserve Clearing Prices shall be determined every five minutes and such determinations shall be the basis of the settlement of sales and purchases of energy in the Real-Time Energy Market, the settlement associated with the provision of Operating Reserve in Real-Time and the settlement of Congestion Costs and costs for losses under the Transmission, Markets and Services Tariff not covered by the Day-Ahead Energy Market. As described in Section III.2.6, every offer and bid by a Market Participant that is scheduled in the Day-Ahead Energy Market will be utilized in the calculation of Day-Ahead Locational Marginal Prices.

III.2.3 Determination of System Conditions Using the State Estimator.

Power system operations, including, but not limited to, the determination of the least costly means of serving load and system and zonal Real-Time Operating Reserve requirements, depend upon the availability of a complete and consistent representation of generator outputs, loads, and power flows on the network. In calculating Day-Ahead Prices, the ISO shall base the system conditions on the expected transmission system configuration and the set of offers and bids submitted by Market Participants. In

calculating Real-Time Locational Marginal Prices and Real-Time Reserve Clearing Prices, the ISO shall obtain a complete and consistent description of conditions on the electric network in the New England Control Area by using the power flow solution produced by the State Estimator for the pricing interval, which is also used by the ISO for other functions within power system operations. The State Estimator is a standard industry tool that produces a power flow model based on available Real-Time metering information, information regarding the current status of lines, generators, transformers, and other equipment, bus load distribution factors, and a representation of the electric network, to provide a complete description of system conditions, including conditions at Nodes and External Nodes for which Real-Time information is unavailable. In calculating Real-Time Locational Marginal Prices and Real-Time Reserve Clearing Prices, the ISO shall obtain a State Estimator solution every five minutes, which shall provide the megawatt output of generators and the loads at Locations in the New England Control Area, transmission line losses, penalty factors, and actual flows or loadings on constrained transmission facilities. External Transactions between the New England Control Area and other Control Areas shall be included in the Real-Time Locational Marginal Price calculation on the basis of the Real-Time transaction schedules implemented by the ISO's dispatcher.

III.2.4 Adjustment for Rapid Response Pricing Assets.

For any Real-Time pricing interval during which a Rapid Response Pricing Asset is committed by the ISO, is in a dispatchable mode, and is not Self-Scheduled, the energy offer of that Rapid Response Pricing Asset shall be adjusted as described in this Section III.2.4 for purposes of the price calculations described in Section III.2.5 and Section III.2.7A. For purposes of the adjustment described in this Section III.2.4, if no Start-Up Fee, No-Load Fee, or Interruption Cost is specified in the submitted Offer Data, a value of zero shall be used; if no Minimum Run Time or Minimum Reduction Time is specified in the submitted Offer Data, or if the submitted Minimum Run Time or Minimum Reduction Time is less than 15 minutes, a duration of 15 minutes shall be used; and the energy offer after adjustment shall not exceed $2,000/MWh.

(a) If the Rapid Response Pricing Asset is a Fast Start Generator or a Flexible DNE Dispatchable Generator, its Economic Minimum Limit shall be set to zero; if the Rapid Response Pricing Asset is a Binary Storage DARD, its Minimum Consumption Limit shall be set to zero; if the Rapid Response Pricing Asset is a Fast Start Demand Response Resource, its Minimum Reduction shall be set to zero.

(b) If the Rapid Response Pricing Asset is a Fast Start Generator or a Flexible DNE Dispatchable Generator that has not satisfied its Minimum Run Time, its energy offer shall be increased by: (i) the

Start-Up Fee divided by the product of the Economic Maximum Limit and the Minimum Run Time; and (ii) the No-Load Fee divided by the Economic Maximum Limit.

(c) If the Rapid Response Pricing Asset is a Fast Start Generator or a Flexible DNE Dispatchable Generator that has satisfied its Minimum Run Time, its energy offer shall be increased by the No-Load Fee divided by the Economic Maximum Limit.

(d) If the Rapid Response Pricing Asset is a Fast Start Demand Response Resource that has not satisfied its Minimum Reduction Time, its energy offer shall be increased by the Interruption Cost divided by the product of the Maximum Reduction and the Minimum Reduction Time.

(e) If the Rapid Response Pricing Asset is a Fast Start Demand Response Resource that has satisfied its Minimum Reduction Time, its energy offer shall not be increased.

III.2.5 Calculation of Nodal Real-Time Prices.

(a) The ISO shall determine the least costly means of obtaining energy to serve the next increment of load at each Node internal to the New England Control Area represented in the State Estimator and each External Node Location between the New England Control Area and an adjacent Control Area, based on the system conditions described by the power flow solution produced by the State Estimator for the pricing interval. This calculation shall be made by applying an optimization method to minimize energy cost, given actual system conditions, a set of energy offers and bids (adjusted as described in Section III.2.4), and any binding transmission and Operating Reserve constraints that may exist. In performing this calculation, the ISO shall calculate the cost of serving an increment of load at each Node and External Node from all available Generator Assets (excluding Settlement Only Resources), Demand Response Resources, External Transaction purchases submitted under Section III.1.10.7 and Dispatchable Asset Related Demands with an eligible energy offer as the sum of: (1) the price at which the Market Participant has offered to supply or consume an additional increment of energy from the Resource; (2) the effect on Congestion Costs (whether positive or negative) associated with increasing the output of the Resource or reducing consumption of the Resource, based on the effect of increased output from that Resource or reduced consumption from that Resource on transmission line loadings; and (3) the effect on Congestion Costs (whether positive or negative) associated with increasing the Operating Reserve requirement, based on the effect of Resource re-dispatch on transmission line loadings; (4) the effect on Congestion Costs (whether positive or negative) associated with a deficiency in Operating Reserve, based on the effect of the Reserve Constraint Penalty Factors described under Section III.2.7A(c); and (5) the

effect on transmission losses caused by the increment of load, generation and demand reduction. The energy offer or offers and energy bid or bids that can jointly serve an increment of load and an increment of Operating Reserve requirement at a Location at the lowest cost, calculated in this manner, shall determine the Real-Time Price at that Node or External Node. For an external interface for which the enhanced scheduling procedures in Section III.1.10.7.A are implemented, the Real-Time Price at the External Node shall be further adjusted to include the effect on Congestion Costs (whether positive or negative) associated with a binding constraint limiting the external interface schedule, as determined when the interface is scheduled.

(b) During the Operating Day, the calculation set forth in this Section III.2.5 shall be performed for every five-minute interval, using the ISO's Locational Marginal Price program, producing a set of nodal Real-Time Prices based on system conditions during the pricing interval. The prices produced at five-minute intervals during an hour will be integrated to determine the nodal Real-Time Prices for that hour.

(c) For any interval during any hour in the Operating Day that the ISO has declared a Minimum Generation Emergency, the affected nodal Real-Time Prices calculated under this Section III.2.5 shall be set equal to the Energy Offer Floor for all Nodes within the New England Control Area and all External Nodes.

III.2.6 Calculation of ~~Nodal~~ Day-Ahead Prices.

III.2.6.1 Calculation of Day-Ahead Locational Marginal Prices.

(a) For the Day-Ahead Energy Market, Day-Ahead Locational Marginal Prices shall be determined on the basis of the least-cost, security-constrained unit commitment and dispatch, model flows and system conditions resulting from the load specifications submitted by Market Participants, Supply Offers, Demand Reduction Offers and Demand Bids for Resources, Increment Offers, Decrement Bids, ~~and~~ External Transactions, and, commencing on June 1, 2024, the Forecast Energy Requirement Demand Quantity, Day-Ahead Ancillary Service demand quantities, and Energy Call Option Offers submitted to the ISO and scheduled in the Day-Ahead Energy Market.

Such prices shall be determined in accordance with the provisions of this Section applicable to the Day-Ahead Energy Market and shall be the basis for the settlement of purchases and sales of energy, costs for losses and Congestion Costs resulting from the Day-Ahead Energy Market. This calculation shall be made for each hour in the Day-Ahead Energy Market by applying an optimization method to minimize

energy and, commencing on June 1, 2024, ancillary services cost, given scheduled system conditions, scheduled transmission outages, and any transmission limitations that may exist. In performing this calculation, the ISO shall calculate the cost of serving an increment of load at each Node and External Node from each Resource associated with an eligible energy offer, ~~or~~ energy bid, or Energy Call Option Offer as the sum of: (1) the price at which the Market Participant has offered to supply an additional increment of energy from the Resource or reduce consumption from the Resource and, commencing on June 1, 2024, the effect on ancillary service costs associated with increasing the output of the Resource or reducing consumption of the Resource; (2) the effect on transmission Congestion Costs (whether positive or negative) associated with increasing the output of the Resource or reducing consumption of the Resource, based on the effect of increased output from that Resource or reduced consumption from a Resource on transmission line loadings; and (3) the effect on transmission losses caused by the increment of load and supply. The energy offer or offers, Energy Call Option Offer or offers, and energy bid or bids that can serve an increment of load at a Node or External Node at the lowest cost, calculated in this manner, shall determine the Day-Ahead Locational Marginal Price at that Node.

For External Nodes for which the enhanced scheduling procedures in Section III.1.10.7.A are implemented, the clearing process specified in the previous two paragraphs shall apply. For all other External Nodes, the following process shall apply: in addition to determining the quantity cleared via the application of transmission constraints (i.e., limits on the flow over a line or set of lines), the quantity cleared is limited via the application of a nodal constraint (i.e., a limit on the total net injections at a Node) that restricts the net amount of cleared transactions to the transfer capability of the external interface. Clearing prices at all Nodes will reflect the marginal cost of serving the next increment of load at that Node while reflecting transmission constraints. A binding nodal constraint will result in interface limits being followed, but will not directly affect the congestion component of an LMP at an External Node.

(b) Energy deficient conditions. If the sum of Day-Ahead fixed Demand Bids and fixed External Transaction sales cannot be satisfied with the sum of all scheduled External Transaction purchases, cleared Increment Offers, and available supply at the Generator Asset’s Economic Maximum Limit and demand reduction at the Demand Response Resource’s Maximum Reduction, the technical software issues an Emergency Condition warning message due to a shortage of economic supply in the Day-Ahead Energy Market. The following steps shall then be performed to achieve power balance:

(i) All fixed External Transaction sales are considered to be dispatchable at the External Transaction Cap;

(ii) Reduce any remaining price-sensitive Demand Bids (including External Transaction sales) and Decrement Bids from lowest price to highest price to zero MW until power balance is achieved (there may be some price sensitive bids that are higher priced than the highest Supply Offer, Demand Reduction Offer, or Increment Offer price cleared). Set LMP values equal to the highest price-sensitive Demand Bid or Decrement Bid that was cut in this step. If no price-sensitive Demand Bid or Decrement Bid was reduced in this step, the LMP values are set equal to highest offer price of all on-line Generator Assets, dispatched Demand Response Resources, Increment Offers or External Transaction purchases; and

(iii) If power balance is not achieved after step (ii), reduce all remaining fixed Demand Bids proportionately (by ratio of load MW) until balance is achieved. Set LMP values equal to the highest offer price of all on-line Generator Assets (excluding Settlement Only Resources), dispatched Demand Response Resources, Increment Offers or External Transaction purchases or the price from step (ii), whichever is higher.

(c) Excess energy conditions. If the sum of Day-Ahead cleared Demand Bids, Decrement Bids and External Transaction sales is less than the total system wide supply (including fixed External Transaction purchases) with all possible Generator Assets off line and with all remaining Generator Assets at their Economic Minimum Limit, the technical software issues a Minimum Generation Emergency warning message due to an excess of economic supply in the Day-Ahead Energy Market. The following steps shall then be performed to achieve power balance:

(i) All fixed External Transaction purchases are considered to be dispatchable at the Energy Offer Floor and reduced pro-rata, as applicable, until power balance is reached;

(ii) If power balance is not reached in step (i), reduce all committed Generator Assets down proportionately by ratio of Economic Minimum Limits, but not below Emergency Minimum Limits. If power balance is achieved prior to reaching Emergency Minimum Limits, set LMP values equal to the lowest offer price of all on-line Generator Assets (excluding Settlement Only Resources); and

(iii) If power balance not achieved in step (ii), set LMP values to Energy Offer Floor and reduce all Generator Assets generation below Emergency Minimum Limits proportionately (by ratio of Emergency Minimum Limits) to achieve power balance.

III.2.6.2 Calculation of Additional Day-Ahead Prices.

(a) Commencing on June 1, 2024, the ISO shall calculate hourly Day-Ahead Prices for additional requirements in the Day-Ahead Energy Market as described in this Section III.2.6.2(a).

(i) The clearing price for Day-Ahead Four-Hour Reserve shall be the incremental cost, as measured by the change in the Day-Ahead Energy Market's security-constrained economic dispatch objective value, to satisfy the next increment of the Day-Ahead Total Four-Hour Reserve Demand Quantity.

(ii) The clearing price for Day-Ahead Ninety-Minute Reserve shall be the sum of (a) the incremental cost, as measured by the change in the Day-Ahead Energy Market's security-constrained economic dispatch objective value, to satisfy the next increment of the Day-Ahead Total Ninety-Minute Reserve Demand Quantity, and (b) the clearing price for Day-Ahead Four-Hour Reserve.

(iii) The clearing price for Day-Ahead Thirty-Minute Operating Reserve shall be the sum of (a) the incremental cost, as measured by the change in the Day-Ahead Energy Market's security-constrained economic dispatch objective value, to satisfy the next increment of the Day-Ahead Total Thirty-Minute Operating Reserve Demand Quantity, and (b) the clearing price for Day-Ahead Ninety-Minute Reserve.

(iv) The clearing price for Day-Ahead Ten-Minute Non-Spinning Reserve shall be the sum of (a) the incremental cost, as measured by the change in the Day-Ahead Energy Market's security-constrained economic dispatch objective value, to satisfy the next increment of the Day-Ahead Total Ten-Minute Reserve Demand Quantity, and (b) the clearing price for Day-Ahead Thirty-Minute Operating Reserve.

(v) The clearing price for Day-Ahead Ten-Minute Spinning Reserve shall be the sum of (a) the incremental cost, as measured by the change in the Day-Ahead Energy Market's security-constrained economic dispatch objective value, to satisfy the next increment of the Day-Ahead

Ten-Minute Spinning Reserve Demand Quantity, and (b) the clearing price for Day-Ahead Ten-Minute Non-Spinning Reserve.

(vi) The clearing price for Day-Ahead Energy Imbalance Reserve shall be the Forecast Energy Requirement Price.

(vii) The Forecast Energy Requirement Price shall be the marginal cost, as measured by the change in the Day-Ahead Energy Market's security-constrained economic dispatch objective value, to satisfy the next increment of the Forecast Energy Requirement Demand Quantity.

(b) **Reserve Constraint Penalty Factors.** The Day-Ahead Energy Market scheduling pursuant to Section III.1.10.8(a)(ii), and the Day-Ahead Prices specified in Section III.2.6, shall respect the applicable Reserve Constraint Penalty Factors specified below:

(i) The Reserve Constraint Penalty Factor applicable to the Day-Ahead Ten-Minute Spinning Reserve Demand Quantity shall be equal to the Real-Time Ten-Minute Spinning Reserve Requirement Reserve Constraint Penalty Factor specified in Section III.2.7A.

(ii) The Reserve Constraint Penalty Factor applicable to the Day-Ahead Total Ten-Minute Reserve Demand Quantity shall be equal to the Real-Time Ten-Minute Reserve Requirement Reserve Constraint Penalty Factor specified in Section III.2.7A.

(iii) The Reserve Constraint Penalty Factor applicable to the Day-Ahead Total Thirty-Minute Operating Reserve Demand Quantity shall be equal to the Real-Time Minimum Total Reserve Requirement Reserve Constraint Penalty Factor specified in Section III.2.7A.

(iv) The Reserve Constraint Penalty Factor applicable to the Day-Ahead Total Ninety-Minute Reserve Demand Quantity shall be equal to $250/MWh.

(v) The Reserve Constraint Penalty Factor applicable to the Day-Ahead Total Four-Hour Reserve Demand Quantity shall be equal to $100/MWh.

(vi) The Reserve Constraint Penalty Factor applicable to the Forecast Energy Requirement Demand Quantity shall be set at 101% of the sum of the Reserve Constraint Penalty Factors in Sections III.2.6.2(b)(i)-(v).

III.2.7 Reliability Regions, Load Zones, Reserve Zones, Zonal Prices and External Nodes.

(a) The ISO shall calculate Zonal Prices for each Load Zone and DRR Aggregation Zone for both the Day-Ahead Energy Market and Real-Time Energy Markets using a load-weighted average of the Locational Marginal Prices for the Nodes within that Load Zone or DRR Aggregation Zone. The load weights used in calculating the Day-Ahead Zonal Prices for the Load Zone and DRR Aggregation Zone shall be determined in accordance with applicable Market Rule 1 provisions and shall be based on historical load usage patterns. The load weights do not reflect Demand Bids or Decrement Bids that settle at the Node level in the Day-Ahead Energy Market. The ISO shall determine, in accordance with applicable ISO New England Manuals, the load weights used in Real-Time based on the actual Real-Time load distribution as calculated by the State Estimator, and shall exclude any Asset Related Demand from the load weights used to calculate the applicable Real-Time Zonal Prices.

(b) Each Load Zone shall initially be approximately coterminous with a Reliability Region.

(c) Reserve Zones shall be established by the ISO which represent areas within the New England Transmission System that require local 30 minute contingency response as part of normal system operations in order to satisfy local 2nd contingency response reliability criteria.

(d) The remaining area within the New England Transmission System that is not included within the Reserve Zones established under Section III.2.7(c) is Rest of System.

(e) Each Reserve Zone shall be completely contained within a Load Zone or shall be defined as a subset of the Nodes contained within a Load Zone.

(f) The ISO shall calculate Forward Reserve Clearing Prices and Real-Time Reserve Clearing Prices for each Reserve Zone.

(g) After consulting with the Market Participants, the ISO may reconfigure Reliability Regions, Load Zones, Dispatch Zones, and Reserve Zones and add or subtract Reliability Regions, Load Zones, Dispatch

Zones, and Reserve Zones as necessary over time to reflect changes to the grid, patterns of usage, changes in local TMOR contingency response requirements and intrazonal Congestion. The ISO shall file any such changes with the Commission.

(h) In the event the ISO makes changes to a Reliability Region or Load Zone or adds or subtracts Reliability Regions and Load Zones, for settlement purposes and to the extent practicable, Load Assets that are physically located in one Reliability Region and electrically located within another Reliability Region shall be located within the Reliability Region to which they are electrically located.

(i) External Nodes are the nodes at which External Transactions settle. As appropriate and after consulting with Market Participants, the ISO will establish and re-configure External Nodes taking into consideration appropriate factors, which may include: tie line operational matters, FTR modeling and auction assumptions, market power issues associated with external contractual arrangements, impacts on Locational Marginal Prices, and inter-regional trading impacts.

(j) On or about the 20th calendar day of each month, the ISO shall publish the Real-Time nodal load weights (expressed in MW) used to calculate the load-weighted Real-Time Zonal Prices for the preceding month. Nodal load weights will be published for all nodes used in the calculations except for those nodes identified by customers as nodes for which publication would provide individual customer usage data. Any individual customer whose usage data would be revealed by publication of load weight information associated with a specific Node must submit a written request to the ISO to omit the applicable Node from the publication requirement. The request must identify the affected Node and, to the best of the customer's knowledge, the number of customers taking service at the affected Node and the estimated percentage of the total annual load (MWh) at the affected Node period that is attributable to the customer. The information contained in the request must be certified in writing by an officer of the customer's company (if applicable), by an affidavit signed by a person having knowledge of the applicable facts, or by representation of counsel for the customer. The ISO will grant a customer request if it determines based on the information provided that no more than two customers are taking service at the affected Node or that the percentage of the customer's annual load (MWh) at the affected Node is greater than 75 percent of the total load (MWh) at the affected Node. If a customer request is granted and that customer request is the only such customer request within a Load Zone, then the ISO shall randomly select one other Node and not disclose hourly load information for the randomly selected Node unless and until another customer request within the Load Zone is granted. A request to suspend publication for a month must be received by the ISO on or before the 10th calendar day of the following month in order to be

effective for that month. Upon receipt of a request, the ISO will suspend publication of the load weight data for the specified Node. The ISO may, from time to time, require customer confirmation that continued omission from publication of load weight data for a particular Node is required in order to avoid disclosure of individual customer usage data. If customer confirmation is not received within a reasonable period not to exceed 30 days, the ISO may publish load weight data for the applicable Node.

III.2.7A Calculation of Real-Time Reserve Clearing Prices.

(a) The ISO shall obtain Operating Reserve in Real-Time to serve Operating Reserve requirements for the system and each Reserve Zone on a jointly optimized basis with the calculation of nodal Real-Time Prices specified under Section III.2.5, based on the system conditions described by the power flow solution produced by the State Estimator program for the pricing interval. This calculation shall be made by applying an optimization method to maximize social surplus, given actual system conditions, a set of energy offers and bids, and any binding transmission constraints, including binding transmission interface constraints associated with meeting Operating Reserve requirements, and binding Operating Reserve constraints that may exist. In performing this calculation, the ISO shall calculate, on a jointly optimized basis with serving an increment of load at each Node and External Node, the cost of serving an increment of Operating Reserve requirement for the system and each Reserve Zone from all available Generator Assets (excluding Settlement Only Resources), Demand Response Resources and Dispatchable Asset Related Demands with an eligible energy offer or bid. Real-Time Reserve Clearing Prices will be equal to zero unless system re-dispatch is required in order to meet the system and zonal Operating Reserve requirements or there is a deficiency in available Operating Reserve, in which case Real-Time Reserve Clearing Prices shall be set as described in Section III.2.7A(b) and Section III.2.7A(c).

(b) If system re-dispatch is required to maintain sufficient levels of Operating Reserve, the applicable Real-Time Reserve Clearing Price is equal to the highest unit-specific Real-Time Reserve Opportunity Cost associated with all Generator Assets, Demand Response Resources and Dispatchable Asset Related Demands that were re-dispatched to meet the applicable Operating Reserve requirement. The Real-Time Reserve Opportunity Cost of a Resource shall be equal to the difference between (i) the Real-Time Energy LMP at the Location for the Resource and (ii) the offer price associated with the re-dispatch of the Resource necessary to create the additional Operating Reserve.

(c) If there is insufficient Operating Reserve available to meet the Operating Reserve requirements for the system and/or any Reserve Zone or sufficient Operating Reserve is not available at a redispatch

cost equal to or less than that specified by the Reserve Constraint Penalty Factors, the applicable Real-Time Reserve Clearing Prices shall be set based upon the following Reserve Constraint Penalty Factors:

Real-Time Requirement	Reserve Constraint Penalty Factor
Zonal Reserve Requirement (combined amount of TMSR, TMNSR, and TMOR required for a Reserve Zone)	$250/MWh
Minimum Total Reserve Requirement (does not include Replacement Reserve) (combined amount of TMSR, TMNSR, and TMOR required system-wide)	$1000/MWh
Total Reserve Requirement (includes Replacement Reserve) (combined amount of TMSR, TMNSR, and TMOR required system-wide)	$250/MWh
Ten-Minute Reserve Requirement (combined amount of TMSR and TMNSR required system-wide)	$1500/MWh
Ten-Minute Spinning Reserve Requirement (amount of TMSR required system-wide)	$50/MWh

The Reserve Constraint Penalty Factors shall be applied in a manner that is consistent with the price cascading described in Section III.2.7A(d).

(d) Real-Time Reserve designations and Real-Time Reserve Clearing Prices shall be calculated in such a manner to ensure that excess Real-Time Operating Reserve capability will cascade down for use in meeting any remaining Real-Time Operating Reserve requirements from TMSR to TMNSR to TMOR and that the pricing of Real-Time Operating Reserve shall cascade up from TMOR to TMNSR to TMSR.

(e) During the Operating Day, the calculation set forth in this Section III.2.7A shall be performed for every five-minute interval, using the ISO’s Unit Dispatch System and Locational Marginal Price program, producing a set of zonal Real-Time Reserve Clearing Prices based on system conditions for the pricing interval. The prices produced at five-minute intervals during an hour will be integrated to determine the Real-Time Reserve Clearing Prices for the system and/or each Reserve Zone for that hour.

III.2.8 Hubs and Hub Prices.

(a) On behalf of the Market Participants, the ISO shall maintain and facilitate the use of a Hub or Hubs for the Day-Ahead Energy Market and Real-Time Energy Market, comprised of a set of Nodes

within the New England Control Area, which Nodes shall be identified by the ISO on its internet website. The ISO has used the following criteria to establish an initial Hub and shall use the same criteria to establish any additional Hubs:

(i) Each Hub shall contain a sufficient number of Nodes to try to ensure that a Hub Price can be calculated for that Hub at all times;

(ii) Each Hub shall contain a sufficient number of Nodes to ensure that the unavailability of, or an adjacent line outage to, any one Node or set of Nodes would have only a minor impact on the Hub Price;

(iii) Each Hub shall consist of Nodes with a relatively high rate of service availability;

(iv) Each Hub shall consist of Nodes among which transmission service is relatively unconstrained; and

(v) No Hub shall consist of a set of Nodes for which directly connected load and/or generation at that set of Nodes is dominated by any one entity or its Affiliates.

(b) The ISO shall calculate and publish Hub Prices for both the Day-Ahead and Real-Time Energy Markets based upon the arithmetic average of the Locational Marginal Prices of the nodes that comprise the Hub.

III.2.9A Final Real Time Prices, Real-Time Reserve Clearing and Regulation Clearing Prices.

(a) The ISO normally will post provisional Real-Time Prices, Real-Time Reserve Clearing Prices and Regulation clearing prices in Real-Time or soon thereafter. The ISO shall post the final Real-Time Prices, final Real-Time Reserve Clearing Prices and final Regulation clearing prices as soon as practicable following the Operating Day, in accordance with the timeframes specified in the ISO New England Manuals, except that the posting of such final Real-Time Prices, final Real-Time Reserve Clearing Prices and final Regulation clearing prices by the ISO shall not exceed five business days from the applicable Operating Day. If the ISO is not able to calculate Real-Time Prices, Real-Time Reserve Clearing Prices or Regulation clearing prices normally due to human error, hardware, software, or telecommunication problems that cannot be remedied in a timely manner, the ISO will calculate Real-

Time Prices, Real-Time Reserve Clearing Prices or Regulation clearing prices as soon as practicable using the best data available; provided, however, in the event that the ISO is unable to calculate and post final Real-Time Prices, Real-Time Reserve Clearing Prices or Regulation clearing prices due to exigent circumstances not contemplated in this market rule, the ISO shall make an emergency filing with the Commission within five business days from the applicable Operating Day detailing the exigent circumstance, which will not allow the final clearing prices to be calculated and posted, along with a proposed resolution including a timeline to post final clearing prices.

(b) The permissibility of correction of errors in Real-Time Prices, Real-Time Reserve Clearing Prices or Regulation clearing prices for an Operating Day due to database, software or similar errors of the ISO or its systems, and the timeframes and procedures for permitted corrections, are addressed solely in this Section III.2.9A and not in those sections of Market Rule 1 relating to settlement and billing processes.

III.2.9B Final Day-Ahead Energy Market Results

(a) Day-Ahead Energy Market results are final when published except as provided in this subsection. If the ISO determines based on reasonable belief that there may be one or more errors in the Day-Ahead Energy Market results for an Operating Day or if no Day-Ahead Energy Market results are available due to human error, database, software or similar errors of the ISO or its systems, the ISO shall post on the ISO website prior to 12:01 a.m. of the applicable Operating Day, a notice that the results are provisional and subject to correction or unavailable for initial publishing. Any Day-Ahead Energy Market results for which no notice is posted shall be final and not subject to correction or other adjustment, and shall be used for purposes of settlement. The ISO shall confirm within three business days of the close of the applicable Operating Day whether there was an error in any provisional Day-Ahead Energy Market results and shall post a notice stating its findings.

(b) The ISO will publish corrected Day-Ahead Energy Market results within three business days of the close of the applicable Operating Day or the results of the Day-Ahead Energy Market for the Operating Day will stand; provided, however, in the event that the ISO is unable to calculate and post final Day-Ahead Energy Market Results due to exigent circumstances not contemplated in this market rule, the ISO shall make an emergency filing with the Commission within five business days from the applicable Operating Day detailing the exigent circumstance, which will not allow the final prices to be calculated and posted, along with a proposed resolution including a timeline to post final prices. The ISO shall also publish a statement describing the nature of the error and the method used to correct the results.

(c) If the ISO determines in accordance with subsection (a) that there are one or more errors in the Day-Ahead Energy Market results for an Operating Day, the ISO shall calculate corrected Day-Ahead Energy Market results by determining and substituting for the initial results, final results that reasonably reflect how the results would have been calculated but for the errors. To the extent that it is necessary, reasonable and practicable to do so, the ISO may specify an allocation of any costs that are not otherwise allocable under applicable provisions of Market Rule 1. The ISO shall use the corrected results for purposes of settlement.

(d) For every change in the Day-Ahead Energy Market results made pursuant to Section III.2.9B, the ISO will prepare and submit, as soon as practicable, an informational report to the Commission describing the nature of any errors, the precise remedy administered, the method of determining corrected prices and allocating any costs, and any remedial actions that will be taken to avoid similar errors in the future.

(e) The permissibility of correction of errors in Day-Ahead Energy Market results, and the timeframes and procedures for permitted corrections, are addressed solely in this Section III.2.9B and not in those sections of Market Rule 1 relating to settlement and billing processes.

III.3 Accounting And Billing

III.3.1 Introduction.

This Section III.3 sets forth the accounting and billing principles and procedures for the purchase and sale of services in the New England Markets and for the operation of the New England Control Area.

If a dollar-per-MW-hour value is applied in a calculation where the interval of the value produced in that calculation is less than an hour, then for purposes of that calculation the dollar-per-MW-hour value is divided by the number of intervals in the hour.

III.3.2 Market Participants.

III.3.2.1 ISO Energy Market.

For purposes of establishing the following positions, unless otherwise expressly stated, the settlement interval for the Real-Time Energy Market is five minutes and the settlement interval for the Day-Ahead Energy Market is hourly. The Real-Time Energy Market settlement is determined using the Metered Quantity For Settlement calculated in accordance with Section III.3.2.1.1.

(a)(1) **Day-Ahead Energy Market Energy Obligations** – For each Market Participant for each settlement interval, the ISO will determine a Day-Ahead Energy Market position representing that Market Participant's net purchases from or sales to the Day-Ahead Energy Market as follows:

(i) **Day-Ahead Load Obligation** – Each Market Participant shall have for each settlement interval a Day-Ahead Load Obligation for energy at each Location equal to the MWhs of its Demand Bids, Decrement Bids and External Transaction sales accepted by the ISO in the Day-Ahead Energy Market at that Location and such Day-Ahead Load Obligation shall have a negative value.

(ii) **Day-Ahead Generation Obligation** – Each Market Participant shall have for each settlement interval a Day-Ahead Generation Obligation for energy at each Location equal to the MWhs of its Supply Offers, Increment Offers and External Transaction purchases accepted by the ISO in the Day-Ahead Energy Market at that Location and such Day-Ahead Generation Obligation shall have a positive value.

(iii) **Day-Ahead Demand Reduction Obligation** – Each Market Participant shall have for each settlement interval a Day-Ahead Demand Reduction Obligation at each Location equal to the MWhs of its Demand Reduction Offers accepted by the ISO in the Day-Ahead Energy Market at that Location, increased by average avoided peak distribution losses. Day-Ahead Demand Reduction Obligations shall have a positive value.

(iv) **Day-Ahead Adjusted Load Obligation** – Each Market Participant shall have for each settlement interval a Day-Ahead Adjusted Load Obligation at each Location equal to the Day-Ahead Load Obligation adjusted by any applicable Day-Ahead internal bilateral transactions at that Location.

(v) **Day-Ahead Locational Adjusted Net Interchange** – Each Market Participant shall have for each settlement interval a Day-Ahead Locational Adjusted Net Interchange at each Location equal to the Day-Ahead Adjusted Load Obligation plus the Day-Ahead Generation Obligation plus the Day-Ahead Demand Reduction Obligation at that Location.

(a)(2) **Day-Ahead Energy Market Ancillary Services Obligations** – Commencing on June 1, 2024, each Market Participant with an Energy Call Option Offer that is accepted by the ISO in the Day-Ahead Energy Market shall have for each settlement interval a Day-Ahead Ancillary Services obligation as follows:

(i) **Day-Ahead Ten-Minute Spinning Reserve Obligation** – A Market Participant with an accepted Energy Call Option Offer quantity that contributes to satisfying the Day-Ahead Ten-Minute Spinning Reserve Demand Quantity shall receive a Day-Ahead Ten-Minute Spinning Reserve Obligation.

(ii) **Day-Ahead Ten-Minute Non-Spinning Reserve Obligation** – A Market Participant with an accepted Energy Call Option Offer quantity that contributes to satisfying the Day-Ahead Total Ten-Minute Reserve Demand Quantity, and that same Energy Call Option Offer quantity does not receive a Day-Ahead Ten-Minute Spinning Reserve Obligation, shall receive a Day-Ahead Ten-Minute Non-Spinning Reserve Obligation.

(iii) **Day-Ahead Thirty-Minute Operating Reserve Obligation** – A Market Participant with an accepted Energy Call Option Offer quantity that contributes to satisfying the Day-Ahead Total

Thirty-Minute Operating Reserve Demand Quantity, and that same Energy Call Option Offer quantity does not receive either a Day-Ahead Ten-Minute Spinning Reserve Obligation or a Day-Ahead Ten-Minute Non-Spinning Reserve Obligation, shall receive a Day-Ahead Thirty-Minute Operating Reserve Obligation.

(iv) **Day-Ahead Ninety-Minute Reserve Obligation** – A Market Participant with an accepted Energy Call Option Offer quantity that contributes to satisfying the Day-Ahead Total Ninety-Minute Reserve Demand Quantity, and that same Energy Call Option Offer quantity does not receive a Day-Ahead Ten-Minute Spinning Reserve Obligation, a Day-Ahead Ten-Minute Non-Spinning Reserve Obligation, or a Day-Ahead Thirty-Minute Operating Reserve Obligation, shall receive a Day-Ahead Ninety-Minute Reserve Obligation.

(v) **Day-Ahead Four-Hour Reserve Obligation** – A Market Participant with an accepted Energy Call Option Offer quantity that contributes to satisfying the Day-Ahead Total Four-Hour Reserve Demand Quantity, and that same Energy Call Option Offer quantity does not receive a Day-Ahead Ten-Minute Spinning Reserve Obligation, a Day-Ahead Ten-Minute Non-Spinning Reserve Obligation, a Day-Ahead Thirty-Minute Operating Reserve Obligation, or a Day-Ahead Ninety-Minute Reserve Obligation, shall receive a Day-Ahead Four-Hour Reserve Obligation.

(vi) **Day-Ahead Energy Imbalance Reserve Obligation** – A Market Participant with an accepted Energy Call Option Offer quantity that contributes to satisfying the Forecast Energy Requirement Demand Quantity shall receive a Day-Ahead Energy Imbalance Reserve Obligation.

(b) **Real-Time Energy Market Obligations Excluding Demand Response Resource Contributions** – For each Market Participant for each settlement interval, the ISO will determine a Real-Time Energy Market position. For purposes of these calculations, if the settlement interval is less than one hour, any internal bilateral transaction shall be equally apportioned over the settlement intervals within the hour. To accomplish this, the ISO will perform calculations to determine the following:

(i) **Real-Time Load Obligation** – Each Market Participant shall have for each settlement interval a Real-Time Load Obligation for energy at each Location equal to the MWhs of load, where such MWhs of load shall include External Transaction sales and shall have a negative value, at that Location, adjusted for unmetered load and any applicable internal bilateral transactions which transfer Real-Time load obligations.

(ii) **Real-Time Generation Obligation** – Each Market Participant shall have for each settlement interval a Real-Time Generation Obligation for energy at each Location. The Real-Time Generation Obligation shall equal the MWhs of energy, where such MWhs of energy shall have positive value, provided by Generator Assets and External Transaction purchases at that Location.

(iii) **Real-Time Adjusted Load Obligation** – Each Market Participant shall have for each settlement interval a Real-Time Adjusted Load Obligation at each Location equal to the Real-Time Load Obligation adjusted by any applicable energy related internal Real-Time bilateral transactions at that Location.

(iv) **Real-Time Locational Adjusted Net Interchange** – Each Market Participant shall have for each settlement interval a Real-Time Locational Adjusted Net Interchange at each Location equal to the Real-Time Adjusted Load Obligation plus the Real-Time Generation Obligation at that Location.

(v) **Marginal Loss Revenue Load Obligation** – Each Market Participant shall have for each settlement interval a Marginal Loss Revenue Load Obligation at each Location equal to the Real-Time Load Obligation adjusted by any energy related internal Real-Time bilateral transactions at that Location that the parties to those bilateral transactions have elected to include in their Marginal Loss Revenue Load Obligation for the purpose of allocating Day-Ahead Loss Revenue and Real-Time Loss Revenue. Contributions from Coordinated External Transactions shall be excluded from the Real-Time Load Obligation for purposes of determining Marginal Loss Revenue Load Obligation.

(c) **Real-Time Energy Market Obligations For Demand Response Resources**

Real-Time Demand Reduction Obligation – Each Market Participant shall have for each settlement interval a Real-Time Demand Reduction Obligation at each Location equal to the MWhs of demand reduction provided by Demand Response Resources at that Location in response to non-zero Dispatch Instructions. The MWhs of demand reduction produced by a Demand Response Resource are equal to the sum of the demand reductions produced by its constituent Demand Response Assets calculated pursuant to Section III.8.4, where the demand reductions, other than MWhs associated with Net Supply, are increased by average avoided peak distribution losses.

(d) **Real-Time Energy Market Deviations Excluding Demand Response Resource Contributions** – For each Market Participant for each settlement interval, the ISO will determine the difference between the Real-Time Energy Market position (calculated in accordance with Section III.3.2.1(b)) and the Day-Ahead Energy Market position (calculated in accordance with Section III.3.2.1(a)(1)) representing that Market Participant's net purchases from or sales to the Real-Time Energy Market (excluding any such transactions involving Demand Response Resources). For purposes of this calculation, if the Real-Time settlement interval is less than one hour, the Day-Ahead position shall be equally apportioned over the settlement intervals within the hour. To accomplish this, the ISO will perform calculations to determine the following:

(i) **Real-Time Load Obligation Deviation** – Each Market Participant shall have for each settlement interval a Real-Time Load Obligation Deviation at each Location equal to the difference in MWhs between the Real-Time Load Obligation and the Day-Ahead Load Obligation.

(ii) **Real-Time Generation Obligation Deviation** – Each Market Participant shall have for each settlement interval a Real-Time Generation Obligation Deviation at each Location equal to the difference in MWhs between the Real-Time Generation Obligation and the Day-Ahead Generation Obligation.

(iii) **Real-Time Adjusted Load Obligation Deviation** – Each Market Participant shall have for each settlement interval a Real-Time Adjusted Load Obligation Deviation at each Location equal to the difference in MWhs between the Real-Time Adjusted Load Obligation and the Day-Ahead Adjusted Load Obligation.

(iv) **Real-Time Locational Adjusted Net Interchange Deviation** – Each Market Participant shall have for each settlement interval a Real-Time Locational Adjusted Net Interchange Deviation at each Location equal to the difference in MWhs between (1) the Real-Time Locational Adjusted Net Interchange and (2) the Day-Ahead Locational Adjusted Net Interchange minus the Day-Ahead Demand Reduction Obligation for that Location.

(e) **Real-Time Energy Market Deviations For Demand Response Resources**

Real-Time Demand Reduction Obligation Deviation – Each Market Participant shall have for each settlement interval a Real-Time Demand Reduction Obligation Deviation at each Location equal to the difference in MWhs between the Real-Time Demand Reduction Obligation (calculated in accordance with Section III.3.2.1(c)) and the Day-Ahead Demand Reduction Obligation (calculated in accordance with Section III.3.2.1(a)(1)). For purposes of this calculation, if the Real-Time settlement interval is less than one hour, the Day-Ahead position shall be equally apportioned over the settlement intervals within the hour.

(f) **Day-Ahead Energy Market Energy Charge/Credit** – For each Market Participant for each settlement interval, the ISO will determine Day-Ahead Energy Market monetary positions representing a charge or credit for its net purchases from or sales to the ISO Day-Ahead Energy Market. The Day-Ahead Energy Market Energy Charge/Credit shall be equal to the sum of its Location specific Day-Ahead Locational Adjusted Net Interchanges multiplied by the Energy Component of the associated Day-Ahead Locational Marginal Prices. The Day-Ahead Energy Market Congestion Charge/Credit shall be equal to the sum of its Location specific Day-Ahead Locational Adjusted Net Interchanges multiplied by the Congestion Component of the associated Day-Ahead Locational Marginal Prices. The Day-Ahead Energy Market Loss Charge/Credit shall be equal to the sum of its Location specific Day-Ahead Locational Adjusted Net Interchanges multiplied by the Loss Component of the associated Day-Ahead Locational Marginal Prices.

(g) **Real-Time Energy Market Charge/Credit Excluding Demand Response Resources** – For each Market Participant for each settlement interval, the ISO will determine Real-Time Energy Market monetary positions representing a charge or credit to the Market Participant for its net purchases from or sales to the Real-Time Energy Market (excluding any such transactions involving Demand Response Resources). The Real-Time Energy Market Deviation Energy Charge/Credit shall be equal to the sum of the Market Participant's Location specific Real-Time Locational Adjusted Net Interchange Deviations for that settlement interval multiplied by the Energy Component of the Real-Time Locational Marginal Prices. The Real-Time Energy Market Deviation Congestion Charge/Credit shall be equal to the sum of the Market Participant's Location specific Real-Time Locational Adjusted Net Interchange Deviations for that settlement interval multiplied by the Congestion Component of the associated Real-Time Locational Marginal Prices. The Real-Time Energy Market Deviation Loss Charge/Credit shall be equal to the sum of the Market Participant's Location specific Real-Time Locational Adjusted Net Interchange Deviations for that settlement interval multiplied by the Loss Component of the associated Real-Time Locational Marginal Prices.

(h) **Real-Time Energy Market Charge/Credit For Demand Response Resources –** For each Market Participant for each settlement interval, the ISO shall calculate a charge or credit to the Market Participant for its net purchases from or sales to the Real-Time Energy Market associated with Demand Response Resources. The charge or credit shall be equal to the sum of the Market Participant's Location-specific Real-Time Demand Reduction Obligation Deviations for that settlement interval multiplied by the Real-Time Locational Marginal Prices. Such charges and credits shall be allocated on an hourly basis to Market Participants based on their pro rata share of the sum of all Market Participants' Real-Time Load Obligation, excluding the Real-Time Load Obligation incurred at all External Nodes, and excluding Real-Time Load Obligation incurred by Storage DARDs.

(i) **Day-Ahead and Real-Time Congestion Revenue** – For each settlement interval, the ISO will determine the total revenues associated with transmission congestion on the New England Transmission System. To accomplish this, the ISO will perform calculations to determine the following. The Day-Ahead Congestion Revenue shall equal the sum of all Market Participants' Day-Ahead Energy Market Congestion Charge/Credits. The Real-Time Congestion Revenue shall equal the sum of all Market Participants' Real-Time Energy Market Deviation Congestion Charge/Credits.

(j) **Day-Ahead Loss Revenue** – For each settlement interval, the ISO will determine the excess or deficiency in loss revenue associated with the Day-Ahead Energy Market. The Day-Ahead Loss Revenue shall be equal to the sum of all Market Participants' Day-Ahead Energy Market Energy Charge/Credits and Day-Ahead Energy Market Loss Charge/Credits.

(k) **Day-Ahead Loss Charges or Credits** – For each settlement interval for each Market Participant, the ISO shall calculate a Day-Ahead payment or charge associated with the excess or deficiency in loss revenue (Section III.3.2.1(j)). The Day-Ahead Loss Charges or Credits shall be equal to the Day-Ahead Loss Revenue multiplied by the Market Participant's pro rata share of the sum of all Market Participants' Marginal Loss Revenue Load Obligations.

(l) **Real-Time Loss Revenue** – For each settlement interval, the ISO will determine the excess or deficiency in loss revenue associated with the Real-Time Energy Market. The Real-Time Loss Revenue shall be equal to the sum of all Market Participants' Real-Time Energy Market Deviation Energy Charge/Credit and Real-Time Energy Market Deviation Loss Charge/Credit plus Non-Market Participant Transmission Customer loss costs. The ISO will then adjust Real-Time Loss Revenue to account for

Inadvertent Energy Revenue, as calculated under Section III.3.2.1(o) and Emergency transactions as described under Section III.4.3(a).

(m) **Real-Time Loss Revenue Charges or Credits** – For each hour for each Market Participant, the ISO shall calculate a Real-Time payment or charge associated with the excess or deficiency in Real-Time Loss Revenue (Section III.3.2.1(l)). The Real-Time Loss Revenue Charges or Credits shall be equal to the Real-Time Loss Revenue multiplied by the Market Participant's pro rata share of the sum of all Market Participants' Marginal Loss Revenue Load Obligations.

(n) **Non-Market Participant Loss** – Non-Market Participant Transmission Customer loss costs shall be assessed for transmission use scheduled in the Real-Time Energy Market, calculated as the amount to be delivered in each settlement interval multiplied by the difference between the Loss Component of the Real-Time Price at the delivery point or New England Control Area boundary delivery interface and the Loss Component of the Real-Time Price at the source point or New England Control Area boundary source interface.

(o) **Inadvertent Energy Revenue** – For each External Node, for each settlement interval the ISO will calculate an excess or deficiency in Inadvertent Energy Revenue by multiplying the Inadvertent Interchange at the External Node by the associated Real-Time Locational Marginal Price. For each settlement interval, the total Inadvertent Energy Revenue for a settlement interval shall equal the sum of the Inadvertent Energy Revenue values for each External Node for that interval.

(p) **Inadvertent Energy Revenue Charges or Credits** – For each hour for each Market Participant, the ISO shall calculate a Real-Time payment or charge associated with the excess or deficiency in Inadvertent Energy Revenue (Section III.3.2.1(o)). The Inadvertent Energy Revenue Charges or Credits shall be equal to the Inadvertent Energy Revenue multiplied by the Market Participant's pro rata share of the sum of all Market Participants' Real-Time Load Obligations, Real-Time Generation Obligations, and Real-Time Demand Reduction Obligations over all Locations, measured as absolute values, excluding contributions to Real-Time Load Obligations and Real-Time Generation Obligations from Coordinated External Transactions.

(q)(1) **Day-Ahead Energy Market Ancillary Services Credit** – Commencing on June 1, 2024, each Market Participant with a Day-Ahead Ancillary Services obligation shall receive a credit as follows:

(i) **Day-Ahead Ten-Minute Spinning Reserve credit** – Each MWh of Day-Ahead Ten-Minute Spinning Reserve Obligation shall be credited the clearing price for Day-Ahead Ten-Minute Spinning Reserve calculated in accordance with Section III.2.6.2(a)(v).

(ii) **Day-Ahead Ten-Minute Non-Spinning Reserve credit** – Each MWh of Day-Ahead Ten-Minute Non-Spinning Reserve Obligation shall be credited the clearing price for Day-Ahead Ten-Minute Non-Spinning Reserve calculated in accordance with Section III.2.6.2(a)(iv).

(iii) **Day-Ahead Thirty-Minute Operating Reserve credit** – Each MWh of Day-Ahead Thirty-Minute Operating Reserve Obligation shall be credited the clearing price for Day-Ahead Thirty-Minute Operating Reserve calculated in accordance with Section III.2.6.2(a)(iii).

(iv) **Day-Ahead Ninety-Minute Reserve credit** – Each MWh of Day-Ahead Ninety-Minute Reserve Obligation shall be credited the clearing price for Day-Ahead Ninety-Minute Reserve calculated in accordance with Section III.2.6.2(a)(ii).

(v) **Day-Ahead Four-Hour Reserve credit** – Each MWh of Day-Ahead Four-Hour Reserve Obligation shall be credited the clearing price for Day-Ahead Four-Hour Reserve calculated in accordance with Section III.2.6.2(a)(i).

(vi) **Day-Ahead Energy Imbalance Reserve credit** – Each MWh of Day-Ahead Energy Imbalance Reserve Obligation shall be credited the clearing price for Day-Ahead Energy Imbalance Reserve calculated in accordance with Section III.2.6.2(a)(vi).

(q)(2) **Day-Ahead Energy Market Ancillary Services Close-Out Charge** – Commencing on June 1, 2024, each Market Participant with a Day-Ahead Ancillary Service obligation shall receive a charge as follows:

(i) **Day-Ahead Generation Contingency Reserve and Day-Ahead Replacement Energy Reserve –** Each MWh of Day-Ahead Ten-Minute Spinning Reserve Obligation, Day-Ahead Ten-Minute Non-Spinning Reserve Obligation, Day-Ahead Thirty-Minute Operating Reserve Obligation, Day-Ahead Ninety-Minute Reserve Obligation, and Day-Ahead Four-Hour Reserve Obligation shall be charged the close-out charge rate, which shall be the greater of (a) the hourly Real-Time Hub Price less the Energy Call Option Strike Price for the hour, and (b) zero.

(ii) **Day-Ahead Energy Imbalance Reserve –** Each MWh of Day-Ahead Energy Imbalance Reserve Obligation shall be charged the close out charge rate determined in accordance with subsection (q)(2)(i).

(q)(3) **Allocation of Net Day-Ahead Generation Contingency Reserve and Day-Ahead Replacement Energy Reserve Credits/Charges** – Commencing on June 1, 2024:

(i) The sum total credits calculated in accordance with Sections III.3.2.1(q)(1)(i)-(v) for Day-Ahead Generation Contingency Reserve and Day-Ahead Replacement Energy Reserve shall be charged on an hourly basis to Market Participants based on their pro rata share of the sum of all Market Participants' Real-Time Load Obligation, excluding Real-Time Load Obligation incurred by Storage DARDs;

(ii) The sum total close-out charges calculated in accordance with Section III.3.2.1(q)(2)(i) for Day-Ahead Generation Contingency Reserve and Day-Ahead Replacement Energy Reserve shall be credited on an hourly basis to Market Participants based on their pro rata share of the sum of all Market Participants' Real-Time Load Obligation, excluding Real-Time Load Obligation incurred by Storage DARDs.

(q)(4) **Allocation of Net Day-Ahead Energy Imbalance Reserve Credits/Charge** – Commencing on June 1, 2024:

(i) For purposes of this subsection (q)(4), the ISO will calculate a load deviation amount for each Market Participant. The load deviation shall be equal to the greater of (a) the MWh amount of the Market Participant's Real-Time Load Obligation (excluding Real-Time Load Obligation incurred by Storage DARDs) minus its Day-Ahead Load Obligation (excluding Day-Ahead Load Obligation incurred by Storage DARDs), or (b) zero.

(ii) The sum of credits calculated in accordance with Section III.3.2.1(q)(1)(vi) for Day-Ahead Energy Imbalance Reserve, if non-zero, shall be charged to Market Participants on an hourly basis as follows:

If the sum of (a) all Market Participants' load deviations and (b) accepted Increment Offers is

equal to or less than the total Day-Ahead Energy Imbalance Reserve Obligation amount, each Market Participant shall be charged: (1) the Day-Ahead Energy Imbalance Reserve clearing price, calculated in accordance with Section III.2.6.2(a)(vi) of this Market Rule 1, multiplied by the Market Participant's accepted Increment Offer amount, and (2) the Day-Ahead Energy Imbalance Reserve clearing price multiplied by the Market Participant's load deviation amount. The balance of any remaining credits for Day-Ahead Energy Imbalance Reserve Obligation shall be charged to Market Participants based on their pro rata share of the sum of all Market Participants' Real-Time Load Obligation, excluding Real-Time Load Obligation incurred by Storage DARDs.

If the sum of (a) all Market Participants' load deviations and (b) accepted Increment Offers is greater than the total Day-Ahead Energy Imbalance Reserve Obligation amount, and if the sum of all Market Participants' load deviations is greater than zero, each Market Participant shall be charged the Day-Ahead Energy Imbalance Reserve clearing price, calculated in accordance with Section III.2.6.2(a)(vi) of this Market Rule 1, multiplied by the Market Participant's accepted Increment Offer amount. The balance of any remaining credits for Day-Ahead Energy Imbalance Reserve Obligation shall be charged to Market Participants based on their pro rata share of the sum of all Market Participants' load deviations.

If the sum of all Market Participants' accepted Increment Offers is greater than the total Day-Ahead Energy Imbalance Reserve Obligation amount, and if the sum of all Market Participants' load deviations is zero, each MWh of a Market Participant's accepted Increment Offer shall be charged the Day-Ahead Energy Imbalance Reserve clearing price, calculated in accordance with Section III.2.6.2(a)(vi) of this Market Rule 1, multiplied by the total Day-Ahead Energy Imbalance Reserve Obligation amount and divided by the sum of all Market Participants' accepted Increment Offer amounts.

(iii) The sum of close-out charges calculated in accordance with Section III.3.2.1(q)(2)(ii) for Day-Ahead Energy Imbalance Reserve, if non-zero, shall be allocated to Market Participants on an hourly basis as follows:

If the sum of (a) all Market Participants' load deviations and (b) accepted Increment Offers is equal to or less than the total Day-Ahead Energy Imbalance Reserve Obligation amount, each Market Participant shall be credited an amount equal to: (1) close-out charge rate determined in

accordance with Section III.3.2.1(q)(2)(ii) for the settlement interval multiplied by the Market Participant's accepted Increment Offer amount, and (2) the close-out charge rate determined in accordance with Section III.3.2.1(q)(2)(ii) for the settlement interval, multiplied by their load deviation amount. The balance of any remaining charges for Day-Ahead Energy Imbalance Reserve Obligations shall be credited to Market Participants based on their pro rata share of the sum of all Market Participants' Real-Time Load Obligation, excluding Real-Time Load Obligation incurred by Storage DARDs.

If the sum of (a) all Market Participants' load deviations and (b) accepted Increment Offers is greater than the total Day-Ahead Energy Imbalance Reserve Obligation amount, and if the sum of all Market Participants' load deviations is greater than zero, each Market Participant shall be credited an amount equal to the close-out charge rate determined in accordance with Section III.3.2.1(q)(2)(ii) for the settlement interval multiplied by the Market Participant's accepted Increment Offer amount. The balance of any remaining charges for Day-Ahead Energy Imbalance Reserve Obligation shall be credited to Market Participants based on their pro rata share of the sum of all Market Participants' load deviations.

If the sum of all Market Participants' accepted increment Offers is greater than the total Day-Ahead Energy Imbalance Reserve Obligation amount, and if the sum of all Market Participants' load deviations is zero, each MWh of a Market Participant's accepted Increment Offer shall be credited an amount equal to the close-out charge rate determined in accordance with Section III.3.2.1(q)(2)(ii) for the settlement interval multiplied by the Market Participant's accepted Increment Offer amount, multiplied by the total Day-Ahead Energy Imbalance Reserve Obligation amount and divided by the sum of all Market Participants' accepted Increment Offer amounts.

(q)(5) **Forecast Energy Requirement Credit -** Commencing on June 1, 2024, Market Participants with Generator Assets, Demand Response Resources, and External Transactions for the supply of energy scheduled in the Day-Ahead Energy Market shall be credited the Forecast Energy Requirement Price, calculated in accordance with Section III.2.6.2(a)(vii), for each MWh of the resource's Day-Ahead energy obligation.

(q)(6) **Forecast Energy Requirement Charge** – The total amount credited in accordance with Section III.3.2.1(q)(5) shall be charged on an hourly basis to Market Participants as follows:

(i) Market Participants shall be charged the Forecast Energy Requirement Price, calculated in accordance with Section III.2.6.2(a)(vii), for each MWh of the Market Participant's Day-Ahead External Transaction sales.

(ii) The balance of any remaining credits shall be charged to Market Participants based on their pro rata share of the sum of all Market Participants' Real-Time Load Obligations, excluding Real-Time Load Obligations incurred by Real-Time External Transaction sales and Storage DARDs.

III.3.2.1.1 Metered Quantity For Settlement.

For purposes of determining the Metered Quantity For Settlement, the five-minute telemetry value for a five-minute interval is the integrated value of telemetered data sampled over the five-minute period. For settlement calculations that require hourly revenue quality meter value from Resources that submit five-minute revenue quality meter data, the hourly revenue quality meter value is the average of five-minute revenue quality meter values for the hour. The Metered Quantity For Settlement is calculated as follows:

(a) For external interfaces, the Metered Quantity For Settlement is the scheduled value adjusted for any curtailment, except that for Inadvertent Interchange, the Metered Quantity For Settlement is the difference between the actual and scheduled values, where the actual value is

(i) calculated as the five-minute telemetry value plus the difference between the hourly revenue quality meter value and the hourly average telemetry value, or

(ii) the five-minute revenue quality meter value, if five-minute revenue quality meter data are available.

(b) For Resources submitting five-minute revenue quality meter data (other than Demand Response Resources), the Metered Quantity For Settlement is the five-minute revenue quality meter value.

(c) For Resources with telemetry submitting hourly revenue quality meter data, the Metered Quantity For Settlement is calculated as follows:

(i) In the event that in an hour, the difference between the average of the five-minute telemetry values for the hour and the revenue quality meter value for the hour is greater than 20 percent of the hourly revenue quality meter value and greater than 10 MW then the Metered Quantity For Settlement is a flat profile of the revenue quality meter value equal to the hourly revenue quality meter value equally apportioned over the five-minute intervals in the hour. (For a Continuous Storage Facility, the difference between the

average of the five-minute telemetry values and the revenue quality meter value will be determined using the net of the values submitted by its component Generator Asset and DARD.)

(ii) Otherwise, the Metered Quantity For Settlement is the telemetry profile of the revenue quality meter value equal to the five-minute telemetry value adjusted by a scale factor.

(d) For a Demand Response Resource, the Metered Quantity For Settlement equals the sum of the demand reductions of each of its constituent Demand Response Assets produced in response to a non-zero Dispatch Instruction, with the demand reduction for each such asset calculated pursuant to Section III.8.4.

(e) For Resources without telemetry submitting hourly revenue quality meter data, the Metered Quantity For Settlement is the hourly revenue quality meter value equally apportioned over the five-minute intervals in the hour.

III.3.2.2 Metering and Communication.

(a) Revenue Quality Metering and Telemetry for Assets other than Demand Response Assets

The megawatt-hour data of each Generator Asset, Tie-Line Asset, and Load Asset must be metered and automatically recorded at no greater than an hourly interval using metering located at the asset's point of interconnection, in accordance with the ISO operating procedures on metering and telemetering. This metered value is used for purposes of establishing the hourly revenue quality metering of the asset.

The instantaneous megawatt data of each Generator Asset (except Settlement Only Resources) and each Asset Related Demand must be automatically recorded and telemetered in accordance with the requirements in the ISO operating procedures on metering and telemetering.

(b) Meter Maintenance and Testing for all Assets

Each Market Participant must adequately maintain metering, recording and telemetering equipment and must periodically test all such equipment in accordance with the ISO operating procedures on metering and telemetering. Equipment failures must be addressed in a timely manner in accordance with the requirements in the ISO operating procedures on maintaining communications and metering equipment.

(c) Additional Metering and Telemetry Requirements for Demand Response Assets

(i) Market Participants must report to the ISO in real time a set of telemetry data for each Demand Response Asset associated with a Demand Response Resource. The telemetry values shall measure the real-time demand of Demand Response Assets as measured at their Retail Delivery Points, and shall be reported to the ISO every five minutes. For a

Demand Response Resource to provide TMSR or TMNSR, Market Participants must in addition report telemetry values at least every one minute. Telemetry values reported by Market Participants to the ISO shall be in MW units and shall be an instantaneous power measurement or an average power value derived from an energy measurement for the time interval from which the energy measurement was taken.

(ii) If one or more generators whose output can be controlled is located behind the Retail Delivery Point of a Demand Response Asset, other than emergency generators that cannot operate electrically synchronized to the New England Transmission System, then the Market Participant must also report to the ISO, before the end of the Correction Limit for the Data Reconciliation Process, a single set of meter data, at an interval of five minutes, representing the combined output of all generators whose output can be controlled.

(iii) If the Market Participant or the ISO finds that the metering or telemetry devices do not meet the accuracy requirements specified in the ISO New England Manuals and Operating Procedures, the Market Participant shall promptly notify the ISO and indicate when it expects to resolve the accuracy problem(s), or shall request that the affected Demand Response Assets be retired. Once such an issue becomes known and until it is resolved, the demand reduction value and Operating Reserve capability of any affected Demand Response Asset shall be excluded from the Demand Response Resource with which it is associated.

(iv) The ISO may review and audit testing and calibration records, audit facility performance (including review of facility equipment), order and witness the testing of metering and telemetry measurement equipment, and witness the demand reduction activities of any facility or generator associated with a Demand Response Asset. Market Participants must make retail billing meter data and any interval meter data from the Host Participant for the facilities associated with a Demand Response Asset available to the ISO upon request.

(d) Overuse of Flat Profiling

In the event a Market Participant’s telemetry is replaced with an hourly flat profile pursuant to Section III.3.2.1.1(c)(i) more than 20% of the online hours in a month and Market Participant’s Resource has been online for over 50 hours in the month, the ISO may consult with the Market Participant for an explanation of the regular use of flat profiling and may request that the Market Participant address any telemetry discrepancies so that flat profiling is not regularly triggered.

Within 10 business days of issuance of such a request, the Market Participant shall provide the ISO with a written plan for remedying the deficiencies, and shall identify in the plan the specific actions to be taken and a reasonable timeline for completing such remediation. The Market Participant shall complete the remediation in accordance with and under the timeline set forth in the written plan.

III.3.2.3 NCPC Credits and Charges.

A Market Participant's NCPC Credits and NCPC Charges are calculated pursuant to Appendix F to Market Rule 1.

III.3.2.4 Transmission Congestion.

Market Participants shall be charged or credited for Congestion Costs as specified in Section III.3.2.1(i) of this Market Rule 1.

III.3.2.5 [Reserved.]

III.3.2.6 Emergency Energy.

(a) For each settlement interval during an hour in which there are Emergency Energy purchases, the ISO calculates an Emergency Energy purchase charge or credit equal to the Emergency Energy purchase price minus the External Node Real-Time LMP for the interval, multiplied by the Emergency Energy quantity for the interval. The charge or credit for each interval in an hour is summed to an hourly value. The ISO allocates the hourly charges or credits to Market Participants based on the following hourly deviations where such deviations are negative: (i) Real-Time Adjusted Load Obligation Deviations during that Operating Day; (ii) generation deviations and demand reduction deviations for those Pool-Scheduled Resources and Continuous Storage Generator Assets that are not following Dispatch Instructions; Self-Scheduled Resources (other than Continuous Storage Generator Assets) with dispatchable capability above their Self-Scheduled amounts not following Dispatch Instructions; and Self-Scheduled Resources (other than Continuous Storage Generator Assets) not following their Day-Ahead Self-Scheduled amounts other than those following Dispatch Instructions; in MWhs during the Operating Day; and (iii) deviations from the Day-Ahead Energy Market for External Transaction purchases in MWhs during the Operating Day except that positive Real-Time Generation Obligation Deviation at External Nodes associated with Emergency Energy purchases are not included in this calculation. Generator Assets and Demand Response Resources shall have a 5% or 5 MWh threshold when determining such deviations. Notwithstanding the foregoing, the allocation of costs or credits attributable to the purchase of Emergency

Energy from other Control Areas shall exclude contributions to deviations from Coordinated External Transactions.

(b) For each settlement interval during an hour in which there are Emergency Energy sales, the ISO calculates Emergency Energy sales revenue, exclusive of revenue from the Real-Time Energy Market, received from other Control Areas to provide the Emergency Energy sales. The revenues for each interval in an hour is summed to an hourly value. Hourly net revenues attributable to the sale of Emergency Energy to other Control Areas shall be credited to Market Participants based on the following deviations where such deviations are negative: (i) Real-Time Adjusted Load Obligation Deviations in MWhs during that Operating Day; (ii) generation deviations and demand reduction deviations for those Pool-Scheduled Resources and Continuous Storage Generator Assets that are following Dispatch Instructions; and Self-Scheduled Generator Assets (other than Continuous Storage Generator Assets) with dispatchable capability above their Self-Scheduled amounts following Dispatch Instructions; in MWhs during the Operating Day; and (iii) deviations from the Day-Ahead Energy Market for External Transaction purchases in MWhs during the Operating Day except that positive Real-Time Generation Obligation Deviation at External Nodes associated with Emergency Energy purchases are not included in this calculation. Generator Assets and Demand Response Resources shall have a 5% or 5 MWh threshold when determining such deviations. Notwithstanding the foregoing, the calculation of the credit for the sale of Emergency Energy to other Control Areas shall exclude contributions to deviations from Coordinated External Transactions.

III.3.2.6A New Brunswick Security Energy.

New Brunswick Security Energy is energy that is purchased from the New Brunswick System Operator by New England to preserve minimum flows on the Orrington-Keswick (396/3001) tie line and Orrington-Lepreau (390/3016) tie line in accordance with the applicable ISO / New Brunswick System Operator transmission operating guide with respect to the determination of minimum transfer limits. New Brunswick Security Energy costs are hourly costs in excess of the LMP at the applicable External Node attributable to purchases of New Brunswick Security Energy by New England. New Brunswick Security Energy costs shall be allocated among Market Participants on the basis of their pro-rata shares of Regional Network Load. Where the LMP at the applicable External Node exceeds the New Brunswick Security Energy costs, such amounts shall be accounted for in accordance with Section III.3.2.1(m).

III.3.2.7 Billing.

The ISO shall prepare a billing statement each billing cycle, in accordance with the ISO New England Billing Policy, for each Market Participant in accordance with the charges and credits specified in Sections III.3.2.1 through III.3.2.6, and showing the net amount to be paid or received by the Market Participant. Billing statements shall provide sufficient detail, as specified in the ISO New England Manuals, ISO New England Administrative Procedures and the ISO New England Billing Policy, to allow verification of the billing amounts and completion of the Market Participant's internal accounting. Billing disputes shall be settled in accordance with procedures specified in the ISO New England Billing Policy.

III.3.3 [Reserved.]

III.3.4 Non-Market Participant Transmission Customers.

III.3.4.1 Transmission Congestion.

Non-Market Participant Transmission Customers shall be charged or credited for Congestion Costs as specified in Section III.1 of this Market Rule 1.

III.3.4.2 Transmission Losses.

Non-Market Participant Transmission Customers shall be charged or credited for transmission losses in an amount equal to the product of (i) the Transmission Customer's MWhs of deliveries in the Real-Time Energy Market, multiplied by (ii) the difference between the Loss Components of the Real-Time Locational Marginal Prices at the point-of-receipt and the point-of-delivery Locations.

III.3.4.3 Billing.

The ISO shall prepare a billing statement each billing cycle, in accordance with the ISO New England Billing Policy, for each Non-Market Participant Transmission Customer in accordance with the charges and credits specified in Sections III.3.4.1 through III.3.4.2 of this Market Rule 1, and showing the net amount to be paid or received by the Non-Market Participant Transmission Customer. Billing statements shall provide sufficient detail, as specified in the ISO New England Manuals, the ISO New England Administrative Procedures and the ISO New England Billing Policy, to allow verification of the billing amounts and completion of the Non-Market Participant Transmission Customer's internal accounting. Billing disputes shall be settled in accordance with procedures specified in the ISO New England Billing Policy.

III.3.5 [Reserved.]

III.3.6 Data Reconciliation.

III.3.6.1 Data Correction Billing.

The ISO will reconcile Market Participant data errors and corrections after the Correction Limit for such data has passed. The Correction Limit for meter data and for ISO errors in the processing of meter and other Market Participant data is 101 days from the last Operating Day of the month to which the data applied. Notification of Meter Data Errors applicable to Assigned Meter Reader or Host Participant Assigned Meter Reader supplied meter data must be submitted to the ISO by the Meter Data Error RBA Submission Limit.

III.3.6.2 Eligible Data.

The ISO will accept revised hourly asset meter readings from Assigned Meter Readers and Host Participant Assigned Meter Readers, daily Coincident Peak Contribution values from Assigned Meter Readers, and new or revised internal bilateral transactions from Market Participants. No other revised data will be accepted for use in settlement recalculations. The ISO will correct data handling errors associated with other Market Participant supplied data to the extent that such data did not impact unit commitment or the Real-Time dispatch. Data handling errors that impacted unit commitment or the Real-Time dispatch will not be corrected.

III.3.6.3 Data Revisions.

The ISO will accept revisions to asset specific meter data, daily Coincident Peak Contribution values, and internal bilateral transactions prior to the Correction Limit. No revisions to other Market Participant data will be accepted after the deadlines specified in the ISO New England Manuals for submittal of that data have passed, except as provided in Section III.3.8 of Market Rule 1. If the ISO discovers a data error or if a Market Participant discovers and notifies the ISO of a data error prior to the Correction Limit, revised hourly data will be used to recalculate all markets and charges as appropriate, including but not limited to energy, NCPC, Regulation, Operating Reserves, Auction Revenue Rights allocations, Forward Capacity Market, cost-of-service agreements, and the ISO Tariff. No settlement recalculations or other adjustments may be made if the Correction Limit for the Operating Day to which the error applied has passed or if the correction does not qualify for treatment as a Meter Data Error correction pursuant to Section III.3.8 of Market Rule 1.

III.3.6.4 Meter Corrections Between Control Areas.

For revisions to meter data associated with assets that connect the New England Control Area to other Control Areas, the ISO will, in addition to performing settlement recalculations, adjust the actual interchange between the New England Control Area and the other Control Area to maintain an accurate record of inadvertent energy flow.

III.3.6.5 Meter Correction Data.

(a) Revised meter data and daily Coincident Peak Contribution values shall be submitted to the ISO as soon as it is available and not later than the Correction Limit, and must be submitted in accordance with the criteria specified in Section III.3.7 of Market Rule 1. Specific data submittal deadlines are detailed in the ISO New England Manuals.

(b) Errors on the part of the ISO in the administration of Market Participant supplied data shall be brought to the attention of the ISO as soon as possible and not later than the Correction Limit.

III.3.7 Eligibility for Billing Adjustments.

(a) Errors in Market Participant's statements resulting from errors in settlement software, errors in data entry by ISO personnel, and settlement production problems, that do not affect the day-ahead schedule or real-time system dispatch, will be corrected as promptly as practicable. If errors are identified prior to the issuance of final statements, the market will be resettled based on the corrected information.

(b) Calculations made by scheduling or dispatch software, operational decisions involving ISO discretion which affect scheduling or real-time operation, and the ISO's execution of mandatory dispatch directions, such as self-schedules or external contract conditions, are not subject to retroactive correction and resettlement. The ISO will settle and bill the Day-Ahead Energy Market as actually scheduled and the Real-Time Energy Market as actually dispatched. Any post-settlement issues raised concerning operating decisions related to these markets will be corrected through revision of operations procedures and guidelines on a prospective basis.

(c) While errors in reporting hourly metered data may be corrected (pursuant to Section III.3.8), Market Participants have the responsibility to ensure the correctness of all data they submit to the market settlement system.

(d) Disputes between Market Participants regarding settlement of internal bilateral transactions shall not be subject to adjustment by the ISO, but shall be resolved directly by the Market Participants unless they involve an error by the ISO that is subject to resolution under Section III.3.7(a).

(e) Billing disputes between Market Participants and the ISO or Non-Market Participants and the ISO shall be settled in accordance with procedures specified in the ISO New England Billing Policy.

(f) Criteria for Meter Data Errors to be eligible for a Requested Billing Adjustment. In order to be eligible to submit a Requested Billing Adjustment due to a Meter Data Error on an Invoice issued by the ISO after the completion of the Data Reconciliation Process, a Market Participant must satisfy one of the following two conditions: (1) the Meter Data Error at issue was identified by the asset owner, Assigned Meter Reader or the Host Participant Assigned Meter Reader and communicated to the Host Participant Assigned Meter Reader no later than thirty-six (36) days prior to the Correction Limit for Directly Metered Assets and no later than two (2) days prior to the Correction Limit for Profiled Load Assets and could not be resolved prior to those deadlines; or (2) the Meter Data Error at issue was identified by the asset owner, Assigned Meter Reader or Host Participant Assigned Meter Reader and reported to the ISO by the Meter Data Error RBA Submission Limit, and such Meter Data Error represents an error that is equal to or greater than the 1,000 MWh per Asset over a calendar month. If the Meter Data Error affects more than one metering domain, the ISO, and affected Host Participant Assigned Meter Readers and affected Assigned Meter Readers of affected metering domains, must be notified.

III.3.8 Correction of Meter Data Errors

(a) Any Market Participant, Assigned Meter Reader or Host Participant Assigned Meter Reader may submit notification of a Meter Data Error in accordance with the procedures provided in this Section III.3.8, provided that the notification is submitted no later than the Meter Data Error RBA Submission Limit and that the notice must be submitted using the RBA form for Meter Data Errors posted on the ISO's website. Errors in telemetry values used in calculating Metered Quantity For Settlement are not eligible for correction under this Section III.3.8.

(b) Within three Business Days of the receipt by the ISO's Chief Financial Officer of an RBA form for a Meter Data Error, the ISO shall prepare and submit to all Covered Entities and to the Chair of the NEPOOL Budget and Finance Subcommittee a notice of the Meter Data Error correction ("Notice of Meter Data Error Correction"), including, subject to the provisions of the ISO New England Information Policy, the specific details of the correction and the identity of the affected metering domains and the

affected Host Participant Assigned Meter Readers. The "Notice of Meter Data Error Correction" shall identify a specific representative of the ISO to whom all communications regarding the matter are to be sent.

(c) In order for a Meter Data Error on an Invoice issued by the ISO after the completion of the Data Reconciliation Process to be eligible for correction, the Meter Data Error must satisfy one of the following conditions: (1) the Meter Data Error at issue was identified by the asset owner, Assigned Meter Reader or the Host Participant Assigned Meter Reader and communicated to the Host Participant Assigned Meter Reader no later than 36 days prior to the Correction Limit for Directly Metered Assets and no later than two days prior to the Correction Limit for Profiled Load Assets and could not be resolved prior to those deadlines; (2) the Meter Data Error at issue was identified by the asset owner, Assigned Meter Reader or Host Participant Assigned Meter Reader, and such Meter Data Error represents an error that is equal to or greater than the 1,000 MWh per asset over a calendar month; and (3) if the Meter Data Error involves only Coincident Peak Contribution values, the average of the daily Meter Data Errors involving Coincident Peak Contribution values for the affected calendar month must be greater than or equal to 5 MW for an affected asset. If the Meter Data Error affects more than one metering domain, the ISO, and affected Host Participant Assigned Meter Readers and affected Assigned Meter Readers of affected metering domains, must be notified.

(d) For a Meter Data Error, the Host Participant Assigned Meter Reader must submit to the ISO corrected meter data for Directly Metered Assets prior to the 46th calendar day after the Meter Data Error RBA Submission Limit. Corrected metered data for Profiled Load Assets and Coincident Peak Contribution values, must be submitted to the ISO by the Host Participant Assigned Meter Reader prior to the 87th calendar day after the Meter Data Error RBA Submission Limit. Corrected internal bilateral transactions data must be submitted to the ISO by a Market Participant prior to the 91st calendar day after the Meter Data Error RBA Submission Limit.

Any corrected data received after the specified deadlines is not eligible for use in the settlement process.

The Host Participant Assigned Meter Reader or Market Participant, as applicable, must confirm as part of its submission of corrected data that the eligibility criteria described in Section III.3.8(c) of Market Rule 1 have been satisfied.

To the extent that the correction of a Meter Data Error is for a Directly Metered Asset that affects multiple metering domains, all affected Host Participant Assigned Meter Readers or Assigned Meter Readers must notify the ISO prior to the 46th calendar day after the Meter Data Error RBA Submission Limit that the corrected Directly Metered Asset data is acceptable to them in order for the ISO to use the corrected data in the final settlement calculations. The Host Participant Assigned Meter Reader for the Directly Metered Asset is responsible for initiating an e-mail to every affected Host Participant Assigned Meter Reader or Assigned Meter Reader in order to obtain such acceptance and shall coordinate delivery of such acceptance to the ISO. The Host Participant Assigned Meter Reader for the Directly Metered Asset is also responsible for submitting all corrected and agreed upon Directly Metered Asset data to the ISO prior to the 46th calendar day after the Meter Data Error RBA Submission Limit.

(e) After the submission of corrected meter and internal bilateral transactions data, the ISO will have a minimum of 30 calendar days to administer the final settlement based on that data. Revised data will be used to recalculate all charges and credits, except that revised data will not be used to recalculate the PER adjustment, including the Hourly PER and Monthly PER values. Revised data will also not be used to recalculate Demand Resource Seasonal Peak Hours. The results of the final settlement will then be included in the next Invoice containing Non-Hourly Charges and the ISO will provide to the Chair of the NEPOOL Budget and Finance Subcommittee written notification that the final settlement has been administered.

III.4 Rate Table

III.4.1 Offered Price Rates.

Day-Ahead energy, Day-Ahead Ancillary Services as of June 1, 2024, Real-Time energy, Regulation, Real-Time Operating Reserve, Forward Reserve, NCPC, Congestion Cost and transmission loss costs are based on offers and bids submitted to the ISO as specified in this Market Rule 1.

III.4.2 [Reserved.]

III.4.3 Emergency Energy Transaction.

The pricing for Emergency Energy and New Brunswick Security Energy purchases and sales will be determined in accordance with:

(a) an applicable agreement with an adjacent Control Area for Emergency and/or New Brunswick Security Energy purchases and sales, or

(b) arrangements made by the ISO with Market Participants, in accordance with procedures defined in the ISO New England Manuals, to purchase Emergency Energy offered by such Market Participant from External Transactions that are not associated with Import Capacity Resources. The ISO shall select offers to sell Emergency Energy made by Market Participants to the ISO on a least cost basis and the selected Market Participants shall receive payment for energy delivered at the higher of their offer price or the Real-Time Price at the applicable External Node. Such Emergency Energy purchases from Market Participants shall not be eligible to set Real-Time Prices.

III.13.2. Annual Forward Capacity Auction.

III.13.2.1. Timing of Annual Forward Capacity Auctions.

Each Forward Capacity Auction will be conducted beginning on the first Monday in the February that is approximately three years and four months before the beginning of the associated Capacity Commitment Period (unless, no later than the immediately preceding December 1, an alternative date is announced by the ISO), or, where exigent circumstances prevent the start of the Forward Capacity Auction at that time, as soon as possible thereafter.

III.13.2.2. Amount of Capacity Cleared in Each Forward Capacity Auction.

The total amount of capacity cleared in each Forward Capacity Auction shall be determined using the System-Wide Capacity Demand Curve and the Capacity Zone Demand Curves for the modeled Capacity Zones pursuant to Section III.13.2.3.3.

III.13.2.2.1. System-Wide Capacity Demand Curve.

The MRI Transition Period is the period from the Forward Capacity Auction for the Capacity Commitment Period beginning June 1, 2020 through the earlier of:

(i) the Forward Capacity Auction for which the amount of the Installed Capacity Requirement (net of HQICCs) that is filed by the ISO with the Commission pursuant to Section III.12.3 for the upcoming Forward Capacity Auction is greater than or equal to the sum of: 34,151 MW, and: (a) 722 MW (for the Forward Capacity Auction for the Capacity Commitment Period beginning June 1, 2020); (b) 375 MW (for the Forward Capacity Auction for the Capacity Commitment Period beginning June 1, 2021), or; (c) 150 MW (for the Forward Capacity Auction for the Capacity Commitment Period beginning June 1, 2022);

(ii) the Forward Capacity Auction for which the product of the system-wide Marginal Reliability Impact value, calculated pursuant to Section III.12.1.1, and the scaling factor specified in Section III.13.2.2.4, specifies a quantity at $7.03/kW-month in excess of the MW value determined under the applicable subsection (2)(b), (2)(c), or (2)(d), below, or;

(iii) the Forward Capacity Auction for the Capacity Commitment Period beginning June 1, 2022.

During the MRI Transition Period, the System-Wide Capacity Demand Curve shall consist of the following three segments:

(1) at prices above $7.03/kW-month and below the Forward Capacity Auction Starting Price, the System-Wide Capacity Demand Curve shall specify a price for system capacity quantities based on the product of the system-wide Marginal Reliability Impact value, calculated pursuant to Section III.12.1.1, and the scaling factor specified in Section III.13.2.2.4;

(2) at prices below $7.03/kW-month, the System-Wide Capacity Demand Curve shall be linear between $7.03/kW-month and $0.00/kW-month and determined by the following quantities:

(a) At the price of $0.00/kW-month, the quantity specified by the System-Wide Capacity Demand Curve shall be 1616 MW plus the MW value determined under the applicable provision in (b), (c), or (d) of this subsection.

(b) for the Forward Capacity Auction for the Capacity Commitment Period beginning June 1, 2020, at $7.03/kW-month, the quantity shall be the lesser of:

1. 35,437 MW; and
2. 722 MW plus the quantity at which the product of the system-wide Marginal Reliability Impact value and the scaling factor yield a price of $7.03/kW-month;

(c) for the Forward Capacity Auction for the Capacity Commitment Period beginning June 1, 2021, at $7.03/kW-month, the quantity shall be the lesser of:

1. 35,090 MW; and
2. 375 MW plus the quantity at which the product of the system-wide Marginal Reliability Impact value and the scaling factor yield a price of $7.03/kW-month;

(d) for the Forward Capacity Auction for the Capacity Commitment Period beginning June 1, 2022, at $7.03/kW-month, the quantity shall be the lesser of:

1. 34,865 MW; and
2. 150 MW plus the quantity at which the product of the system-wide Marginal Reliability Impact value and the scaling factor yield a price of $7.03/kW-month

(3) a price of $7.03/kW-month for all quantities between those curves segments.

In addition to the foregoing, the System-Wide Capacity Demand Curve shall not specify a price in excess of the Forward Capacity Auction Starting Price.

Following the MRI Transition Period, the System-Wide Capacity Demand Curve shall specify a price for system capacity quantities based on the product of the system-wide Marginal Reliability Impact value, calculated pursuant to Section III.12.1.1, and the scaling factor specified in Section III.13.2.2.4. For any system capacity quantity greater than 110% of the Installed Capacity Requirement (net of HQICCs), the System-Wide Capacity Demand Curve shall specify a price of zero. The System-Wide Capacity Demand Curve shall not specify a price in excess of the Forward Capacity Auction Starting Price.

III.13.2.2.2. Import-Constrained Capacity Zone Demand Curves.

For each import-constrained Capacity Zone, the Capacity Zone Demand Curve shall specify a price for all Capacity Zone quantities based on the product of the import-constrained Capacity Zone's Marginal Reliability Impact value, calculated pursuant to Section III.12.2.1.3, and the scaling factor specified in Section III.13.2.2.4. The prices specified by an import-constrained Capacity Zone Demand Curve shall be non-negative. At all quantities greater than the truncation point, which is the amount of capacity for which the Capacity Zone Demand Curve specifies a price of $0.01/kW-month, the Capacity Zone Demand Curve shall specify a price of zero. The Capacity Zone Demand Curve shall not specify a price in excess of the Forward Capacity Auction Starting Price.

III.13.2.2.3. Export-Constrained Capacity Zone Demand Curves.

For each export-constrained Capacity Zone, the Capacity Zone Demand Curve shall specify a price for all Capacity Zone quantities based on the product of the export-constrained Capacity Zone's Marginal Reliability Impact value, calculated pursuant to Section III.12.2.2.1, and the scaling factor specified in Section III.13.2.2.4. The prices specified by an export-constrained Capacity Zone Demand Curve shall be non-positive. At all quantities less than the truncation point, which is the amount of capacity for which the Capacity Zone Demand Curve specifies a price of negative $0.01/kW-month, the Capacity Zone Demand Curve shall specify a price of zero.

III.13.2.2.4. Capacity Demand Curve Scaling Factor.

The demand curve scaling factor shall be set at the value such that, at the quantity specified by the System-Wide Capacity Demand Curve at a price of Net CONE, the Loss of Load Expectation is 0.1 days per year.

III.13.2.3. Conduct of the Forward Capacity Auction.

The Forward Capacity Auction shall include a descending clock auction, which will determine, subject to the provisions of Section III.13.2.7, the Capacity Clearing Price for each Capacity Zone modeled in that Forward Capacity Auction pursuant to Section III.12.4, and the Capacity Clearing Price for certain offers from New Import Capacity Resources and Existing Import Capacity Resources pursuant to Section III.13.2.3.3(d). The Forward Capacity Auction shall determine the outcome of all offers and bids accepted during the qualification process and submitted during the auction. The descending clock auction shall be conducted as a series of rounds, which shall continue (for up to five consecutive Business Days, with up to eight rounds per day, absent extraordinary circumstances) until the Forward Capacity Auction is concluded for all modeled Capacity Zones in accordance with the provisions of Section III.13.2.3.3. Each round of the Forward Capacity Auction shall consist of the following steps, which shall be completed simultaneously for each Capacity Zone included in the round:

III.13.2.3.1. Step 1: Announcement of Start-of-Round Price and End-of-Round Price.

For each round, the auctioneer shall announce a single Start-of-Round Price (the highest price associated with a round of the Forward Capacity Auction) and a single (lower) End-of-Round Price (the lowest price associated with a round of the Forward Capacity Auction). In the first round, the Start-of-Round Price shall equal the Forward Capacity Auction Starting Price for all modeled Capacity Zones. In each round after the first round, the Start-of-Round Price shall equal the End-of-Round Price from the previous round.

III.13.2.3.2. Step 2: Compilation of Offers and Bids.

The auctioneer shall compile all of the offers and bids for that round, as follows:

(a) **Offers from New Generating Capacity Resources, New Import Capacity Resources, and New Demand Capacity Resources.**

(i) The Project Sponsor for any New Generating Capacity Resource, New Import Capacity Resource that is backed by a single new External Resource and that is associated with an investment in transmission that increases New England’s import capability, New Import Capacity

Resource that is associated with an Elective Transmission Upgrade, or New Demand Capacity Resource accepted in the qualification process for participation in the Forward Capacity Auction may submit a New Capacity Offer indicating the quantity of capacity that the Project Sponsor would commit to provide from the resource during the Capacity Commitment Period at that round's prices. A New Capacity Offer shall be defined by the submission of one to five prices, each strictly less than the Start-of-Round Price but greater than or equal to the End-of-Round Price, and an associated quantity in the applicable Capacity Zone. Each price shall be expressed in units of dollars per kilowatt-month to an accuracy of at most three digits to the right of the decimal point, and each quantity shall be expressed in units of MWs to an accuracy of at most three digits to the right of the decimal point. A New Capacity Offer shall imply a supply curve indicating quantities offered at all of that round's prices, pursuant to the convention of Section III.13.2.3.2(a)(iii).

(ii) If the Project Sponsor of a New Generating Capacity Resource, New Import Capacity Resource that is backed by a single new External Resource and that is associated with an investment in transmission that increases New England's import capability, New Import Capacity Resource that is associated with an Elective Transmission Upgrade, or New Demand Capacity Resource elects to offer in a Forward Capacity Auction, the Project Sponsor must offer the resource's full FCA Qualified Capacity at the Forward Capacity Auction Starting Price in the first round of the auction. A New Capacity Offer for a resource may in no event be for greater capacity than the resource's full FCA Qualified Capacity at any price. A New Capacity Offer for a resource may not be for less capacity than the resource's Rationing Minimum Limit at any price, except where the New Capacity Offer is for a capacity quantity of zero.

(iii) Let the Start-of-Round Price and End-of-Round Price for a given round be P_S and P_E, respectively. Let the m prices ($1 \leq m \leq 5$) submitted by a Project Sponsor for a modeled Capacity Zone be $p_1, p_2, \ldots, p_m$, where $P_S > p_1 > p_2 > \ldots > p_m \geq P_E$, and let the associated quantities submitted for a New Capacity Resource be $q_1, q_2, \ldots, q_m$. Then the Project Sponsor's supply curve, for all prices strictly less than P_S but greater than or equal to P_E, shall be taken to be:

$$S(p)=\begin{cases} q_0, & \text{if } p > p_1, \\ q_1, & \text{if } p_2 < p \le p_1, \\ q_2, & \text{if } p_3 < p \le p_2, \\ \cdots & \cdots \quad , \\ q_m, & \text{if } p \le p_m. \end{cases}$$

where, in the first round, q_0 is the resource's full FCA Qualified Capacity and, in subsequent rounds, q_0 is the resource's quantity offered at the lowest price of the previous round.

(iv) Except for Renewable Technology Resources and except as provided in Section III.13.2.3.2(a)(v), a New Capacity Resource may not include any capacity in a New Capacity Offer during the Forward Capacity Auction at any price below the resource's New Resource Offer Floor Price. The amount of capacity included in each New Capacity Offer at each price shall be included in the aggregate supply curves at that price as described in Section III.13.2.3.3.

(v) Capacity associated with a New Import Capacity Resource (other than a New Import Capacity Resource that is backed by a single new External Resource and that is associated with an investment in transmission that increases New England's import capability or a New Import Capacity Resource that is associated with an Elective Transmission Upgrade) shall be automatically included in the aggregate supply curves as described in Section III.13.2.3.3 at prices at or above the resource's offer prices (as they may be modified pursuant to Section III.A.21.2) and shall be automatically removed from the aggregate supply curves at prices below the resource's offer prices (as they may be modified pursuant to Section III.A.21.2), except under the following circumstances:

In any round of the Forward Capacity Auction in which prices are below the Dynamic De-List Bid Threshold, the Project Sponsor for a New Import Capacity Resource (other than a New Import Capacity Resource that is backed by a single new External Resource and that is associated with an investment in transmission that increases New England's import capability or a New Import Capacity Resource that is associated with an Elective Transmission Upgrade) with offer prices (as they may be modified pursuant to Section III.A.21.2) that are less than the Dynamic Delist Bid Threshold may submit a New Capacity Offer indicating the quantity of capacity that the Project Sponsor would commit to provide from the resource during the Capacity Commitment Period at that round's prices. Such an offer shall be defined by the submission of one to five

prices, each less than the Dynamic De-List Bid Threshold (or the Start-of-Round Price, if lower than the Dynamic De-List Bid Threshold) but greater than or equal to the End-of-Round Price, and a single quantity associated with each price. Such an offer shall be expressed in the same form as specified in Section III.13.2.3.2(a)(i) and shall imply a curve indicating quantities at all of that round's relevant prices, pursuant to the convention of Section III.13.2.3.2(a)(iii). The curve may not increase the quantity offered as the price decreases.

(b) **Bids from Existing Capacity Resources**

(i) Static De-List Bids, Permanent De-List Bids, Retirement De-List Bids, and Export Bids from Existing Generating Capacity Resources, Existing Import Capacity Resources, and Existing Demand Capacity Resources, as finalized in the qualification process or as otherwise directed by the Commission shall be automatically bid into the appropriate rounds of the Forward Capacity Auction, such that each such resource's FCA Qualified Capacity will be included in the aggregate supply curves as described in Section III.13.2.3.3 until any Static De-List Bid, Permanent De-List Bid, Retirement D-List Bid, or Export Bid clears in the Forward Capacity Auction, as described in Section III.13.2.5.2, and is removed from the aggregate supply curves. In the case of a Commission-approved Permanent De-List Bid or Commission-approved Retirement De-List Bid at or above the Forward Capacity Auction Starting Price, or where a Permanent De-List Bid or Retirement De-List Bid is subject to an election under Section III.13.1.2.4.1(a), the resource's FCA Qualified Capacity will be reduced by the quantity of the de-list bid (unless the resource was retained for reliability pursuant to Section III.13.1.2.3.1.5.1) and the Permanent De-List Bid or Retirement De-List Bid shall not be included in the Forward Capacity Auction. Permanent De-List Bids and Retirement De-List Bids subject to an election under Section III.13.1.2.4.1(a) or Section III.13.1.2.4.1(b) shall not be included in the Forward Capacity Auction and shall be treated according to Section III.13.2.3.2(b)(ii). In the case of a Static De-List Bid, if the Market Participant revised the bid pursuant to Section III.13.1.2.3.1.1, then the revised bid shall be used in place of the submitted bid; if the Market Participant withdrew the bid pursuant to Section III.13.1.2.3.1.1, then the capacity associated with the withdrawn bid shall be entered into the auction pursuant to Section III.13.2.3.2(c). If the amount of capacity associated with Export Bids for an interface exceeds the transfer limit of that interface (minus any accepted Administrative De-List Bids over that interface), then the set of Export Bids associated with that interface equal to the interface's transfer limit (minus any accepted Administrative De-List Bids over that interface) having the highest bid prices shall be included in the auction as described above;

capacity for which Export Bids are not included in the auction as a result of this provision shall be entered into the auction pursuant to Section III.13.2.3.2(c).

(ii) For Permanent De-List Bids and Retirement De-List Bids, the ISO will enter a Proxy De-List Bid into the appropriate rounds of the Forward Capacity Auction in the following circumstances: (1) if the Lead Market Participant has elected pursuant to Section III.13.1.2.4.1(a) to retire the resource or portion thereof, the resource has not been retained for reliability pursuant to Section III.13.1.2.3.1.5.1, the price specified in the Commission-approved de-list bid is less than the Forward Capacity Auction Starting Price, and the Internal Market Monitor has found a portfolio benefit pursuant to Section III.A.24; or (2) if the Lead Market Participant has elected conditional treatment pursuant to Section III.13.1.2.4.1(b), the resource has not been retained for reliability pursuant to Section III.13.1.2.3.1.5.1, and the price specified in the Commission-approved de-list bid is less than the price specified in the de-list bid submitted by the Lead Market Participant and less than the Forward Capacity Auction Starting Price. The Proxy De-List Bid shall be non-rationable and shall be equal in price and quantity to, and located in the same Capacity Zone as, the Commission-approved Permanent De-List Bid or Commission-approved Retirement De-List Bid, and shall be entered into the appropriate rounds of the Forward Capacity Auction such that the capacity associated with the Proxy De-List Bid will be included in the aggregate supply curves as described in Section III.13.2.3.3 until the Proxy De-List Bid clears in the Forward Capacity Auction, as described in Section III.13.2.5.2, and is removed from the aggregate supply curves. If the Lead Market Participant has elected conditional treatment pursuant to Section III.13.1.2.4.1(b), the resource has not been retained for reliability pursuant to Section III.13.1.2.3.1.5.1, and the Commission-approved Permanent De-List Bid or Commission-approved Retirement De-List Bid is equal to or greater than the de-list bid submitted by the Lead Market Participant, no Proxy De-List Bid shall be used and the Commission-approved de-list bid shall be entered in the Forward Capacity Auction pursuant to Section III.13.2.3.2(b)(i).

(iii) For purposes of this subsection (b), if an Internal Market Monitor-determined price has been established for a Static De-List Bid and the associated resource's capacity is pivotal pursuant to Sections III.A.23.1 and III.A.23.2, then (unless otherwise directed by the Commission) the lower of the Internal Market Monitor-determined price and any revised bid that is submitted pursuant to Section III.13.1.2.3.1.1 will be used in place of the initially submitted bid; provided, however, that if the bid was withdrawn pursuant to Section III.13.1.2.3.1.1, then the capacity associated with the withdrawn bid shall be entered into the auction pursuant to

Section III.13.2.3.2(c). If an Internal Market Monitor-determined price has been established for an Export Bid and the associated resource's capacity is pivotal pursuant to Sections III.A.23.1 and III.A.23.2, then the Internal Market Monitor-determined price (or price directed by the Commission) will be used in place of the submitted bid.

Any Static De-List Bid for ambient air conditions that has not been verified pursuant to Section III.13.1.2.3.2.4 shall not be subject to the provisions of this subsection (b).

(c) **Existing Capacity Resources Without De-List or Export Bids and Self-Supplied FCA Resources**. Each Existing Generating Capacity Resource, Existing Import Capacity Resource, and Existing Demand Capacity Resource without a Static De-List Bid, a Permanent De-List Bid, a Retirement De-List Bid, an Export Bid or an Administrative Export De-List Bid in its Existing Capacity Qualification Package, and each existing Self-Supplied FCA Resource shall be automatically entered into each round of the Forward Capacity Auction at its FCA Qualified Capacity, such that the resource's FCA Qualified Capacity will be included in the aggregate supply curves as described in Section III.13.2.3.3, except where such resource, if permitted, submits an appropriate Dynamic De-List Bid, as described in Section III.13.2.3.2(d). Each new Self-Supplied FCA Resource shall be automatically entered into each round of the Forward Capacity Auction at its designated self-supplied quantity at prices at or above the resource's New Resource Offer Floor Price, such that the resource's designated self-supply quantity will be included in the aggregate supply curves as described in Section III.13.2.3.3.

(d) **Dynamic De-List Bids.** In any round of the Forward Capacity Auction in which prices are below the Dynamic De-List Bid Threshold, any Existing Generating Capacity Resource, Existing Import Capacity Resource, or Existing Demand Capacity Resource (but not any Self-Supplied FCA Resources) may submit a Dynamic De-List Bid at prices below the Dynamic De-List Bid Threshold. Such a bid shall be defined by the submission of one to five prices, each less than the Dynamic De-List Bid Threshold (or the Start-of-Round Price, if lower than the Dynamic De-List Bid Threshold) but greater than or equal to the End-of-Round Price, and a single quantity associated with each price. Such a bid shall be expressed in the same form as specified in Section III.13.2.3.2(a)(i) and shall imply a curve indicating quantities at all of that round's relevant prices, pursuant to the convention of Section III.13.2.3.2(a)(iii). The curve may in no case increase the quantity offered as the price decreases. A dynamic De-List Bid may not offer less capacity than the resource's Rationing Minimum Limit at any price, except where the amount of capacity offered is zero. All Dynamic De-List Bids are subject to a reliability review as described in Section III.13.2.5.2.5, and if not rejected for reliability reasons, shall be included in the round in the same

manner as Static De-List Bids as described in Section III.13.2.3.2(b). Where a resource elected pursuant to Section III.13.1.1.2.2.4 or Section III.13.1.4.1.1.2.7 to have the Capacity Supply Obligation and Capacity Clearing Price continue to apply after the Capacity Commitment Period associated with the Forward Capacity Auction in which the offer clears, the capacity associated with any resulting Capacity Supply Obligation may not be subject to a Dynamic De-List Bid in subsequent Forward Capacity Auctions for Capacity Commitment Periods for which the Project Sponsor elected to have the Capacity Supply Obligation and Capacity Clearing Price continue to apply. Where a Lead Market Participant submits any combination of Dynamic De-List Bid, Static De-List Bid, Export Bid, and Administrative Export De-List Bid for a single resource, none of the prices in a set of price-quantity pairs associated with a bid may be the same as any price in any other set of price-quantity pairs associated with another bid for the same resource.

(e) **Repowering**. Offers and bids associated with a resource participating in the Forward Capacity Auction as a New Generating Capacity Resource pursuant to Section III.13.1.1.1.2 (resources previously counted as capacity resources) shall be addressed in the Forward Capacity Auction in accordance with the provisions of this Section III.13.2.3.2(e). The Project Sponsor shall offer such a New Generating Capacity Resource into the Forward Capacity Auction in the same manner and pursuant to the same rules as other New Generating Capacity Resources, as described in Section III.13.2.3.2(a). As long as any capacity is offered from the New Generating Capacity Resource, the amount of capacity offered is the amount that the auctioneer shall include in the aggregate supply curve at the relevant prices, and the quantity of capacity offered from the associated Existing Generating Capacity Resource shall not be included in the aggregate supply curve. If any portion of the New Generating Capacity Resource clears in the Forward Capacity Auction, the associated Existing Generating Capacity Resource shall be permanently de-listed as of the start of the associated Capacity Commitment Period. If at any price, no capacity is offered from the New Generating Capacity Resource, then the auctioneer shall include capacity from the associated Existing Generating Capacity Resource at that price, subject to any bids submitted and accepted in the qualification process for that Existing Generating Capacity Resource pursuant to Section III.13.1.2.5. Bids submitted and accepted in the qualification process for an Existing Generating Capacity Resource pursuant to Section III.13.1.2.5 shall only be entered into the Forward Capacity Auction after the associated New Generating Capacity Resource is fully withdrawn (that is, the Forward Capacity Auction reaches a price at which the resource's New Capacity Offer is zero capacity), and shall only then be subject to the reliability review described in Section III.13.2.5.2.5.

(f) **Conditional Qualified New Resources.** Offers associated with a resource participating in the Forward Capacity Auction as a Conditional Qualified New Resource pursuant to Section III.13.1.1.2.3(f) shall be addressed in the Forward Capacity Auction in accordance with the provisions of this Section III.13.2.3.2(f). The Project Sponsor shall offer such a Conditional Qualified New Resource into the Forward Capacity Auction in the same manner and pursuant to the same rules as other New Generating Capacity Resources, as described in Section III.13.2.3.2(a). An offer from at most one resource at a Conditional Qualified New Resource's location will be permitted to clear (receive a Capacity Supply Obligation for the associated Capacity Commitment Period) in the Forward Capacity Auction. As long as a positive quantity is offered at the End-of-Round Price in the final round of the Forward Capacity Auction by the resource having a higher queue priority at the Conditional Qualified New Resource's location, as described in Section III.13.1.1.2.3(f), then no capacity from the Conditional Qualified New Resource shall clear. If at any price greater than or equal to the End-of-Round Price in the final round of the Forward Capacity Auction, zero quantity is offered from the resource having higher queue priority at the Conditional Qualified New Resource's location, as described in Section III.13.1.1.2.3(f), then the auctioneer shall consider capacity offered from the Conditional Qualified New Resource in the determination of clearing, including the application of Section III.13.2.7.

(g) **Mechanics**. Offers and bids that may be submitted during a round of the Forward Capacity Auction must be received between the starting time and ending time of the round, as announced by the auctioneer in advance. The ISO at its sole discretion may authorize a participant in the auction to complete or correct its submission after the ending time of a round, but only if the participant can demonstrate to the ISO's satisfaction that the participant was making reasonable efforts to complete a valid offer submission before the ending time of the round, and only if the ISO determines that allowing the completion or correction will not unreasonably disrupt the auction process. All decisions by the ISO concerning whether or not a participant may complete or correct a submission after the ending time of a round are final.

III.13.2.3.3. Step 3: Determination of the Outcome of Each Round.

The auctioneer shall use the offers and bids for the round as described in Section III.13.2.3.2 to determine the aggregate supply curves for the New England Control Area and for each modeled Capacity Zone included in the round.

The aggregate supply curve for the New England Control Area, the Total System Capacity, shall reflect at each price the sum of the following:

(1) the amount of capacity offered in all Capacity Zones modeled as import-constrained Capacity Zones at that price (excluding capacity offered from New Import Capacity Resources and Existing Import Capacity Resources);

(2) the amount of capacity offered in the Rest-of-Pool Capacity Zone at that price (excluding capacity offered from New Import Capacity Resources and Existing Import Capacity Resources);

(3) for each Capacity Zone modeled as an export-constrained Capacity Zone, the lesser of:

  (i) the amount of capacity offered in the Capacity Zone at that price (including the amount of capacity offered from New Import Capacity Resources and Existing Import Capacity Resources for each interface between the New England Control Area and an external Control Area mapped to the export-constrained Capacity Zone up to that interface's approved capacity transfer limit (net of tie benefits)), or;

  (ii) the amount of capacity determined by the Capacity Zone Demand Curve at zero minus that price, and;

(4) for each interface between the New England Control Area and an external Control Area mapped to an import-constrained Capacity Zone or the Rest-of-Pool Capacity Zone, the lesser of:

  (i) that interface's approved capacity transfer limit (net of tie benefits), or;

  (ii) the amount of capacity offered from New Import Capacity Resources and Existing Import Capacity Resources.

In computing the Total System Capacity, capacity associated with any New Capacity Offer at any price greater than the Forward Capacity Auction Starting Price will not be included in the tally of total capacity at the Forward Capacity Auction Starting Price for that Capacity Zone. On the basis of these aggregate supply curves, the auctioneer shall determine the outcome of the round for each modeled Capacity Zone as follows:

(a) **Import-Constrained Capacity Zones.**

For a Capacity Zone modeled as an import-constrained Capacity Zone, if either of the following two conditions is met during the round:

(1) the aggregate supply curve for the import-constrained Capacity Zone, adjusted as necessary in accordance with Section III.13.2.6 (Capacity Rationing Rule), equals or is less than the quantity determined by the Capacity Zone Demand Curve at the difference between the End-of-Round Price and the price specified by the System-Wide Capacity Demand Curve (at a quantity no less than Total System Capacity at the Start-of-Round Price), or;

(2) the Forward Capacity Auction is concluded for the Rest-of-Pool Capacity Zone;

then the Forward Capacity Auction for that Capacity Zone is concluded and such Capacity Zone will not be included in further rounds of the Forward Capacity Auction.

The Capacity Clearing Price for that Capacity Zone shall be set at the greater of: (1) the sum of the price specified by the Capacity Zone Demand Curve at the amount of capacity equal to the total amount that is awarded a Capacity Supply Obligation in the import-constrained Capacity Zone, and the Capacity Clearing Price for the Rest-of-Pool Capacity Zone, or; (2) the highest price of any offer or bid for a resource in the Capacity Zone that is awarded a Capacity Supply Obligation, subject to the other provisions of this Section III.13.2.

If neither of the two conditions above are met in the round, then that Capacity Zone will be included in the next round of the Forward Capacity Auction.

(b) **Rest-of-Pool Capacity Zone**.

If the Total System Capacity at the End-of-Round Price, adjusted as necessary in accordance with Section III.13.2.6 (Capacity Rationing Rule), and adjusted to include the additional supply in the import-constrained Capacity Zone that may be cleared at a higher price, equals or is less than the amount of capacity determined by the System-Wide Capacity Demand Curve, then the Forward Capacity Auction for the Rest-of-Pool Capacity Zone is concluded and the Rest-of-Pool Capacity Zone will not be included in further rounds of the Forward Capacity Auction.

The Capacity Clearing Price for the Rest-of-Pool Capacity Zone shall be set at the highest price at which the Total System Capacity is less than or equal to the amount of capacity determined by the System-Wide Capacity Demand Curve, subject to the other provisions of this Section III.13.2.

If the Forward Capacity Auction for the Rest-of-Pool Capacity Zone is not concluded then the Rest-of-Pool Capacity Zone will be included in the next round of the Forward Capacity Auction, and the auctioneer shall publish the Total System Capacity at the End-of-Round Price, adjusted to include the additional supply in the import-constrained Capacity Zone that may be cleared at a higher price, less the amount of capacity determined by the System-Wide Capacity Demand Curve at the End-of-Round Price.

(c) **Export-Constrained Capacity Zones**.

For a Capacity Zone modeled as an export-constrained Capacity Zone, if all of the following conditions are met during the round:

(1) the aggregate supply curve for the export-constrained Capacity Zone, adjusted as necessary in accordance with Section III.13.2.6 (Capacity Rationing Rule), is equal to or less than the maximum amount of capacity determined by the Capacity Zone Demand Curve at a price of zero;

(2) in the case of a nested Capacity Zone, the Forward Capacity Auction is concluded for the Capacity Zone within which the nested Capacity Zone is located, and;

(3) the Forward Capacity Auction is concluded for the Rest-of-Pool Capacity Zone;

then the Forward Capacity Auction for that Capacity Zone is concluded and such Capacity Zone will not be included in further rounds of the Forward Capacity Auction.

The Capacity Clearing Price for an export-constrained Capacity Zone that is not a nested export-constrained Capacity Zone shall be set at the greater of:

(1) the sum of:

(i) the price specified by the Capacity Zone Demand Curve at the amount of capacity equal to the total amount that is awarded a Capacity Supply Obligation in that Capacity Zone; and

(ii) the Capacity Clearing Price for the Rest-of-Pool Capacity Zone.

or;

(2) the highest price of any offer or bid for a resource in the Capacity Zone that is awarded a Capacity Supply Obligation, and subject to the other provisions of this Section III.13.2.

The Capacity Clearing Price for a nested export-constrained Capacity Zone shall be set at the greater of:

(1) the sum of:

(i) the price specified by the Capacity Zone Demand Curve at the amount of capacity equal to the total amount that is awarded a Capacity Supply Obligation in that Capacity Zone; and

(ii) the Capacity Clearing Price for the Capacity Zone in which the nested Capacity Zone is located,

or;

(2) the highest price of any offer or bid for a resource in the Capacity Zone that is awarded a Capacity Supply Obligation, subject to the other provisions of this Section III.13.2.

If all of the conditions above are not satisfied in the round, then the auctioneer shall publish the quantity of excess supply in the export-constrained Capacity Zone at the End-of-Round Price (the amount of capacity offered at the End-of-Round Price in the export-constrained Capacity Zone minus the maximum amount of capacity determined by the Capacity Zone Demand Curve at a price of zero) and that Capacity Zone will be included in the next round of the Forward Capacity Auction.

(d) **Treatment of Import Capacity.** Where the amount of capacity offered from New Import Capacity Resources and Existing Import Capacity Resources over an interface between the New England Control Area and an external Control Area is less than or equal to that interface's approved capacity transfer limit (net of tie benefits, or net of HQICC in the case of the Phase I/II HVDC-TF), then the capacity offers from those resources shall be treated as capacity offers in the modeled Capacity Zone associated with that interface. Where the amount of capacity offered from New Import Capacity Resources and Existing Import Capacity Resources over an interface between the New England Control Area and an external Control Area is greater than that interface's approved capacity transfer limit (net of tie benefits, or net of HQICC in the case of the Phase I/II HVDC-TF), then the following provisions shall apply (separately for each such interface):

(i) For purposes of determining which capacity offers from the New Import Capacity Resources and Existing Import Capacity Resources over the interface shall clear and at what price, the offers over the interface shall be treated in the descending-clock auction as if they comprised a separately-modeled export-constrained capacity zone, with an aggregate supply curve consisting of the offers from the New Import Capacity Resources and Existing Import Capacity Resources over the interface.

(ii) The amount of capacity offered over the interface that will be included in the aggregate supply curve of the modeled Capacity Zone associated with the interface shall be the lesser of the following two quantities: the amount of capacity offered from New Import Capacity Resources

and Existing Import Capacity Resources over the interface; and the interface's approved capacity transfer limit (net of tie benefits, or net of HQICC in the case of the Phase I/II HVDC-TF).

(iii) The Forward Capacity Auction for New Import Capacity Resources and Existing Import Capacity Resources over the interface is concluded when the following two conditions are both satisfied: the amount of capacity offered from New Import Capacity Resource and Existing Import Capacity Resources over the interface is less than or equal to the interface's approved capacity transfer limit (net of tie benefits, or net of HQICC in the case of the Phase I/II HVDC-TF); and the Forward Capacity Auction is concluded in the modeled Capacity Zone associated with the interface.

(e) **Treatment of Export Capacity.** Any Export Bid or any Administrative Export De-List Bid that is used to export capacity through an export interface connected to an import-constrained Capacity Zone from another Capacity Zone, or through an export interface connected to the Rest-of-Pool Capacity Zone from an export-constrained Capacity Zone in the Forward Capacity Auction will be modeled in the Capacity Zone where the export interface that is identified in the Existing Capacity Qualification Package is located. The Export Bid or Administrative Export De-List Bid clears in the Capacity Zone where the Export Bid or Administrative Export De-List Bid is modeled.

(i) Then the MW quantity equal to the relevant Export Bid or Administrative Export De-List Bid from the resource associated with the Export Bid or Administrative Export De-List Bid will be de-listed in the Capacity Zone where the resource is located. If the export interface is connected to an import-constrained Capacity Zone, the MW quantity procured will be in addition to the amount of capacity determined by the Capacity Zone Demand Curve for the import-constrained Capacity Zone.

(ii) If the Export Bid or Administrative Export De-List Bid does not clear, then the resource associated with the Export Bid or Administrative Export De-List Bid will not be de-listed in the Capacity Zone where the resource is located.

III.13.2.3.4. Determination of Final Capacity Zones.

(a) For all Forward Capacity Auctions up to and including the sixth Forward Capacity Auction (for the Capacity Commitment Period beginning June 1, 2015), after the Forward Capacity Auction is concluded for all modeled Capacity Zones, the final set of distinct Capacity Zones that will be used for all

purposes associated with the relevant Capacity Commitment Period, including for the purposes of reconfiguration auctions and Capacity Supply Obligation Bilaterals, shall be those having distinct Capacity Clearing Prices as a result of constraints between modeled Capacity Zones binding in the running of the Forward Capacity Auction. Where a modeled constraint does not bind in the Forward Capacity Auction, and as a result adjacent modeled Capacity Zones clear at the same Capacity Clearing Price, those modeled Capacity Zones shall be a single Capacity Zone used for all purposes of the relevant Capacity Commitment Period, including for the purposes of reconfiguration auctions and Capacity Supply Obligation Bilaterals.

(b) For all Forward Capacity Auctions beginning with the seventh Forward Capacity Auction (for the Capacity Commitment Period beginning June 1, 2016) the final set of distinct Capacity Zones that will be used for all purposes associated with the relevant Capacity Commitment Period, including for the purposes of reconfiguration auctions and Capacity Supply Obligation Bilaterals, shall be those described in Section III.12.4.

III.13.2.4. Forward Capacity Auction Starting Price and the Cost of New Entry.

The Forward Capacity Auction Starting Price is max [1.6 multiplied by Net CONE, CONE]. References in this Section III.13 to the Forward Capacity Auction Starting Price shall mean the Forward Capacity Auction Starting Price for the Forward Capacity Auction associated with the relevant Capacity Commitment Period.

CONE for the Forward Capacity Auction for the Capacity Commitment Period beginning on June 1, 2021 is $11.35/kW-month.

Net CONE for the Forward Capacity Auction for the Capacity Commitment Period beginning on June 1, 2021 is $8.04/kW-month.

CONE and Net CONE shall be recalculated for the Capacity Commitment Period beginning on June 1, 2025 and no less often than once every three years thereafter. Whenever these values are recalculated, the ISO will review the results of the recalculation with stakeholders and the new values will be filed with the Commission prior to the Forward Capacity Auction in which the new value is to apply.

Between recalculations, CONE and Net CONE will be adjusted for each Forward Capacity Auction pursuant to Section III.A.21.1.2(e). Prior to applying the annual adjustment for the Capacity

Commitment Period beginning on June 1, 2019, Net CONE will be reduced by $0.43/kW-month to reflect the elimination of the PER adjustment. The adjusted CONE and Net CONE values will be published on the ISO's web site.

III.13.2.5. Treatment of Specific Offer and Bid Types in the Forward Capacity Auction.

III.13.2.5.1. Offers from New Generating Capacity Resources, New Import Capacity Resources, and New Demand Capacity Resources.

A New Capacity Offer (other than one from a Conditional Qualified New Resource) clears (receives a Capacity Supply Obligation for the associated Capacity Commitment Period) in the Forward Capacity Auction if the Capacity Clearing Price is greater than or equal to the price specified in the offer, except possibly as a result of the Capacity Rationing Rule described in Section III.13.2.6. An offer from a Conditional Qualified New Resource clears (receives a Capacity Supply Obligation for the associated Capacity Commitment Period) in the Forward Capacity Auction, except possibly as a result of the Capacity Rationing Rule described in Section III.13.2.6, if all of the following conditions are met: (i) the Capacity Clearing Price is greater than or equal to the price specified in the offer; (ii) capacity from that resource is considered in the determination of clearing as described in Section III.13.2.3.2(f); and (iii) such offer minimizes the costs for the associated Capacity Commitment Period, subject to Section III.13.2.7.7(c).

The amount of capacity that receives a Capacity Supply Obligation through the Forward Capacity Auction shall not exceed the quantity of capacity offered from the New Generating Capacity Resource, New Import Capacity Resource, or New Demand Capacity Resource at the Capacity Clearing Price.

III.13.2.5.2. Bids and Offers from Existing Generating Capacity Resources, Existing Import Capacity Resources, and Existing Demand Capacity Resources.

III.13.2.5.2.1. Permanent De-List Bids and Retirement De-List Bids.

(a) Except as provided in Section III.13.2.5.2.5, a Permanent De-List Bid, Retirement De-List Bid or Proxy De-List Bid clears in the Forward Capacity Auction (does not receive a Capacity Supply Obligation) if the Capacity Clearing Price is less than or equal to the price specified in the bid, except possibly as a result of the Capacity Rationing Rule described in Section III.13.2.6.

(b) Unless the capacity has been retained for reliability pursuant to Section III.13.2.5.2.5, if all or part of a resource with a Permanent De-List Bid or Retirement De-List Bid does not clear in the Forward Capacity Auction (receives a Capacity Supply Obligation), the Lead Market Participant shall enter the uncleared portion of the bid into the qualification process for the following Forward Capacity Auction as described in Section III.13.1.2.3.1.5.

(c) If the Capacity Clearing Price is greater than the price specified in a de-list bid submitted by a Lead Market Participant that elected conditional treatment for the de-list bid pursuant to Section III.13.1.2.4.1(b), and there is an associated Proxy De-List Bid that does not clear (receives a Capacity Supply Obligation), the resource will receive a Capacity Supply Obligation at the Capacity Clearing Price.

(d) The process by which the primary auction is cleared (but not the compilation of offers and bids pursuant to Sections III.13.2.3.1 and III.13.2.3.2) will be repeated after the substitution auction is completed if one of the following conditions is met: (1) if any Proxy De-List Bid entered as a result of a Lead Market Participant electing to retire pursuant to Section III.13.1.2.4.1(a) does not clear (receives a Capacity Supply Obligation) in the first run of the primary auction-clearing process and retains some portion of its Capacity Supply Obligation in the substitution auction; or (2) if any Proxy De-List Bid entered as a result of a Lead Market Participant electing conditional treatment pursuant to Section III.13.1.2.4.1(b) does not clear (receives a Capacity Supply Obligation) in the first run of the primary auction-clearing process, the de-list bid submitted by the Lead Market Participant is at or above the Capacity Clearing Price, and the Proxy De-List Bid retains some portion of its Capacity Supply Obligation in the substitution auction. The second run of the primary auction-clearing process: (i) excludes all Proxy De-List Bids, (ii) includes the offers and bids of resources compiled pursuant to Section III.13.2.3.2 that did not receive a Capacity Supply Obligation in the first run of the primary auction-clearing process, excluding the offers, or portion thereof, associated with resources that acquired a Capacity Supply Obligation in the substitution auction, and (iii) includes the capacity of resources, or portion thereof, that retain a Capacity Supply Obligation after the first run of the primary auction-clearing process and the substitution auction. The second run of the primary auction-clearing process shall not affect the Capacity Clearing Price of the Forward Capacity Auction (which is established by the first run of the primary auction-clearing process).

(e) Resources (other than those still subject to a multi-year Capacity Commitment Period election as described in Sections III.13.1.1.2.2.4 and III.13.1.4.1.1.2.7) that receive a Capacity Supply Obligation as a

result of the first run of the primary auction-clearing process shall be paid the Capacity Clearing Price during the associated Capacity Commitment Period. Where the second run of the primary auction-clearing process procures additional capacity, the resulting price, paid during the associated Capacity Commitment Period (and subsequent Capacity Commitment Periods, as elected pursuant to Section III.13.1.1.2.2.4 or Section III.13.1.4.1.1.2.7) to the additionally procured capacity, shall be equal to or greater than the adjusted price resulting from the first run of the primary auction-clearing process for that Capacity Zone.

III.13.2.5.2.2. Static De-List Bids and Export Bids.

Except as provided in Section III.13.2.5.2.5, a Static De-List Bid or an Export Bid clears in the Forward Capacity Auction (does not receive a Capacity Supply Obligation for the associated Capacity Commitment Period) if the Capacity Clearing Price is less than or equal to the price specified in the bid, except possibly as a result of the Capacity Rationing Rule described in Section III.13.2.6.

III.13.2.5.2.3. Dynamic De-List Bids.

A Dynamic De-List Bid clears in the Forward Capacity Auction (does not receive a Capacity Supply Obligation for the associated Capacity Commitment Period) if the Capacity Clearing Price is less than or equal to the price specified in the bid, except possibly as a result of the Capacity Rationing Rule described in Section III.13.2.6. If more Dynamic De-List Bids are submitted at a price than are needed to clear the market, such Dynamic De-List Bids shall be cleared pro-rata, but in no case less than a resource's Rationing Minimum Limit.

III.13.2.5.2.4. Administrative Export De-List Bids.

An Administrative Export De-List Bid clears in the Forward Capacity Auction (does not receive a Capacity Supply Obligation for the associated Capacity Commitment Period) regardless of the Capacity Clearing Price.

III.13.2.5.2.5. Reliability Review.

The ISO shall review each Retirement De-List Bid, Permanent De-List Bid, Static De-List Bid, Export Bid, Administrative Export De-List Bid, Dynamic De-List Bid, and substitution auction demand bid to determine whether the capacity associated with that bid is needed for reliability reasons during the Capacity Commitment Period associated with the Forward Capacity Auction; Proxy De-List Bids shall not be reviewed.

(a) The reliability review of de-list bids will be conducted in descending price order using the price as finalized during qualification or as otherwise directed by the Commission. De-list bids with the same price will be reviewed in the order that produces the least negative impact to reliability; where bids are the same price and provide the same impact to reliability, they will be reviewed based on their submission time. If de-list bids with the same price are from a single generating station, they will be reviewed in an order that seeks to provide (1) the least-cost solution under Section III.13.2.5.2.5.1(d) and (2) the minimum aggregate quantity required for reliability from the generating station. The reliability review of substitution auction demand bids that would otherwise clear will be conducted in order beginning with the resource whose cleared bids contribute the greatest amount to social surplus. The capacity associated with a bid shall be deemed needed for reliability reasons if the absence of the capacity would result in the violation of any NERC or NPCC criteria, or ISO New England System Rules. Bids shall only be rejected pursuant to this Section III.13.2.5.2.5 for the sole purpose of addressing a local reliability issue, and shall not be rejected solely on the basis that acceptance of the bid may result in the procurement of less capacity than the Installed Capacity Requirement (net of HQICCs) or the Local Sourcing Requirement for a Capacity Zone.

(b) If a Retirement De-List Bid, Permanent De-List Bid, Static De-List Bid, Export Bid, Administrative Export De-List Bid, or Dynamic De-List Bid would otherwise clear in the Forward Capacity Auction, but the ISO has determined that some or all of the capacity associated with the de-list bid is needed for reliability reasons, then the de-list bid having capacity needed for reliability will not clear in the Forward Capacity Auction. If the ISO has determined that some or all of the capacity associated with a substitution auction demand bid that would otherwise clear is needed for reliability reasons, then the entire demand bid will not be further included in the substitution auction.

(c) The Lead Market Participant shall be notified that its bid did not clear for reliability reasons at the later of: (i) immediately after the end of the Forward Capacity Auction round in which the auction price reaches the price of the de-list bid; or (ii) as soon as practicable after the time at which the ISO has determined that the bid must be rejected for reliability reasons. In no event, however, shall a Lead Market Participant be notified that a bid submitted pursuant to Section III.13.1.2.5 and accepted in the qualification process for an Existing Generating Capacity Resource did not clear for reliability reasons if the associated New Generating Capacity Resource remains in the Forward Capacity Auction. In such a case, the Lead Market Participant shall be notified that its bid did not clear for reliability reasons at the later of: (i) immediately after the end of the Forward Capacity Auction round in which the auction price reaches the price of the bid; (ii) immediately after the end of the Forward Capacity Auction round in

which the associated New Generating Capacity Resource is fully withdrawn (that is, the Forward Capacity Auction reaches a price at which the resource's New Capacity Offer is zero capacity); or (iii) as soon as practicable after the time at which the ISO has determined that the bid must be rejected for reliability reasons.

(d) A resource that has a de-list bid rejected for reliability reasons shall be compensated pursuant to the terms set out in Section III.13.2.5.2.5.1 and shall have a Capacity Supply Obligation as described in Section III.13.6.1.

(e) The ISO shall review the results of each annual reconfiguration auction and determine whether the reliability need which caused the ISO to reject the de-list bid has been met through the annual reconfiguration auction. The ISO may also attempt to address the reliability concern through other reasonable means (including transmission enhancements).

(f) If the reliability need that caused the ISO to reject a de-list bid is met through a reconfiguration auction or other means, the resource shall retain its Capacity Supply Obligation through the end of the Capacity Commitment Period for which it was retained for reliability (provided that resources that have Permanent De-List Bids or Retirement De-List Bids rejected for reliability shall be permanently de-listed or retired as of the first day of the subsequent Capacity Commitment Period (or earlier if the resource sheds the entirety of the Capacity Supply Obligation as described in Section III.13.2.5.2.5.3(a)(ii) or Section III.13.2.5.2.5.3(b)(ii))).

(g) If a Permanent De-List Bid or a Retirement De-List Bid is rejected for reliability reasons, and the reliability need is not met through a reconfiguration auction or other means, that resource, or portion thereof, as applicable, is no longer eligible to participate as an Existing Capacity Resource in any reconfiguration auction, Forward Capacity Auction or Capacity Supply Obligation Bilateral for that and subsequent Capacity Commitment Periods. If the resource, or portion thereof, continues to be needed for reliability reasons, it shall be counted as capacity in the Forward Capacity Auction and shall be compensated as described in Section III.13.2.5.2.5.1.

(h) The ISO shall review with the Reliability Committee (i) the status of any prior rejected de-list bids reported to the Commission in an FCA results filing pursuant to Section 13.8.2, and (ii) the status of any Retirement De-List Bid or Permanent De-List Bid that has been rejected for reliability reasons and

has elected to continue to operate, prior to the New Capacity Qualification Deadline in accordance with Section 4.1(c) of Attachment K of the ISO OATT.

If an identified reliability need results in the rejection of a Retirement De-List Bid, Permanent De-List Bid, Export Bid, Administrative Export De-List Bid, Static De-List Bid, or Dynamic De-List Bid while executing an FCA, the ISO shall (i) review each specific reliability need with the Reliability Committee in accordance with the timing provided for in the ISO New England Operating Documents and, (ii) update the current system Needs Assessments pursuant to Section 4.1(c) of Attachment K of the ISO OATT. This review and update will follow ISO's filing of the FCA results with the Commission pursuant to Section 13.8.2.

III.13.2.5.2.5A Fuel Security Reliability Review

(a) This Section III.13.2.5.2.5A will remain in effect for the 2022/23~~,~~ and 2023/24 ~~and 2024/25~~ Capacity Commitment Periods, after which this Section III.13.2.5.2.5A will sunset.

(b) This Section III.13.2.5.2.5A will apply to (i) Retirement De-List Bids, (ii) substitution auction demand bids, and (iii) bilateral transactions and reconfiguration auctions demand bids submitted by an Existing Generating Capacity Resource that has been identified as being needed for fuel security during a Forward Capacity Auction. Terms set out in this Section III.13.2.5.2.5A will apply only for the period and resources described within this Section III.13.2.5.2.5A. Where the terms and conditions in this Section III.13.2.5.2.5A differ from terms otherwise set out in Section III.13, the terms of this Section III.13.2.5.2.5A will control for the period and circumstances described in Section III.13.2.5.2.5A.

(c) A fuel security reliability review for the Forward Capacity Market will be performed pursuant to Appendix L to Section III of the Tariff, and in accordance with the inputs and methodology set out to establish the fuel security reliability standard in Appendix I of Planning Procedure No. 10.

(d) For fuel security reliability reviews performed for the primary Forward Capacity Auction, the fuel security reliability review will be performed after the Existing Capacity Retirement Deadline and conducted in descending price order using the price as submitted in the Retirement De-List Bids. Bids with the same price will be reviewed in the order that produces the least negative impact to reliability. Where multiple bids have the same price and the retirement of the Existing Generating Capacity Resources would have the same impact to reliability, they will be reviewed based on their submission

time. If bids with the same price are from a single generating station, they will be reviewed in an order that seeks to provide (1) the least-cost solution under Section III.13.2.5.2.5.1(d), and (2) the minimum aggregate quantity required for reliability from the generating station. An Existing Generating Capacity Resource may be needed for both fuel security and for transmission security pursuant to Section III.13.2.5.2.5. The fuel security reliability review will be performed in advance of the reliability review for transmission security. Where an Existing Generating Capacity Resource is needed for both fuel security reasons pursuant to this Section III.13.2.5.2.5A, and transmission security reliability reasons pursuant to Section III.13.2.5.2.5, the generator will be retained for fuel security for purposes of cost allocation.

(e) If an Existing Generating Capacity Resource is identified as being needed for fuel security reasons, and the reliability need is not met through a reconfiguration auction or other means, that resource, or portion thereof, as applicable may not participate in Annual Reconfiguration Auctions for the Capacity Commitment Period(s) for which it is needed for fuel security, or earlier 2022/23~~,~~ and 2023/24 ~~and 2024/25~~ Capacity Commitment Periods. Such an Existing Generating Capacity Resource that is identified as being needed for fuel security may participate in monthly bilateral transactions and monthly reconfiguration auctions, but may not submit monthly bilateral transactions for December, January or February, or demand bids for the December, January, or February monthly reconfiguration auctions for any period for which they have been identified as being needed for fuel security.

(f) Participants that have submitted a Retirement De-List Bid will be notified by ISO New England if their resource is needed for fuel security reliability reasons no later than 90 days after the Existing Capacity Retirement Deadline. Participants that have submitted a substitution auction demand bid, and where the demand bid has been rejected for reliability reasons, will be notified after the relevant Forward Capacity Auction has been completed.

(g) Where a Retirement De-List Bid would otherwise clear in the Forward Capacity Auction, but the ISO has determined that some or all of the capacity associated with the de-list bid is needed for fuel security reliability reasons, the provisions of III.13.2.5.2.5(b) shall apply.

(h) Existing Generating Capacity Resources that have had their Retirement De-list Bid rejected for fuel security reliability reasons and that do not elect to unconditionally or conditionally retire shall be eligible for compensation pursuant to Section III.13.2.5.2.5.1, except that the difference between payments based on resource de-list bids or cost-of-service compensation as detailed in Section III.13.2.5.2.5.1 and

payments based on the Capacity Clearing Price for the Forward Capacity Market under this Section III.13.2.5.2.5.1 shall be allocated on a regional basis to Real Time Load Obligation, excluding Real-Time Load Obligation associated with Dispatchable Asset Related Demand Resources (DARD Pumps and other electric storage based DARDs) and Real-Time Load Obligation associated with Coordinated External Transactions, allocated and collected over a 12 month period. Resources that that are identified as needed for fuel security reliability reasons will have their capacity entered into the Forward Capacity Auction pursuant to III.13.2.5.2.5(g) and III.13.2.3.2(b).

(i) Where an Existing Generating Capacity Resource elects a cost-of-service agreement pursuant to Section III.13.2.5.2.5.1 to address a fuel security reliability need, the term of such a cost-of-service agreement may not exceed two years, including renewal through evergreen provisions.~~ A cost-of-service agreement entered into for the 2024/2025 Capacity Commitment Period shall be limited to a total duration of one year.~~

(j) The ISO shall perform an annual reevaluation of any Existing Generating Capacity Resources retained for reliability under this provision. If a resource associated with a Retirement De-List Bid that was rejected for reliability reasons pursuant to this section, is found to no longer be needed for fuel security, and is not needed for another reliability reason pursuant to Section III.13.2.5.2.5, the resource will be retired from the system as described in Section III.13.2.5.2.5.3(a)(1). In no case will a resource retained for fuel security be retained for fuel security beyond June 1, 2024~~5~~.

(k) The ISO will review Retirement De-List Bids rejected for fuel security reliability reasons with the Reliability Committee in the same manner as described in Section III.13.2.5.2.5(h).

III.13.2.5.2.5.1. Compensation for Bids Rejected for Reliability Reasons.

(a) In cases where a Static De-List Bid, Export Bid, Administrative Export De-List Bid, Dynamic De-List Bid, partial Permanent De-List Bid, or partial Retirement De-List Bid has been rejected for reliability reasons pursuant to Sections III.13.1.2.3.1.5.1 or III.13.2.5.2.5, the resource will be paid by the ISO in the same manner as all other capacity resources, except that payment shall be made on the basis of its de-list bid as accepted for the Forward Capacity Auction for the relevant Capacity Commitment Period instead of the Forward Capacity Market Clearing Price. Under this Section, accepted Dynamic De-List Bids filed with the Commission as part of the FCA results filing are subject to review and approval by the Commission pursuant to the "just and reasonable" standard of Section 205 of the Federal Power Act. If a resource with a partial Permanent De-List Bid or partial Retirement De-List Bid continues to be needed for reliability in Capacity Commitment Periods following the Capacity Commitment Period for which the partial Permanent De-List Bid or partial Retirement De-List Bid was rejected, payment will continue to be pursuant to this Section III.13.2.5.2.5.1(a).

(b) In cases where a Permanent De-List Bid or a Retirement De-List Bid for the capacity of an entire resource has been rejected for reliability reasons pursuant to Section III.13.1.2.3.1.5.1 or III.13.2.5.2.5, the resource will be paid either (i) in the same manner as all other capacity resources, except that payment shall be made on the basis of its Commission-approved Permanent De-List Bid or Commission-approved Retirement De-List Bid for the relevant Capacity Commitment Period instead of the Forward Capacity Market Clearing Price or (ii) under the terms of a cost-of-service agreement pursuant to Section III, Appendix I. Resources must notify the ISO of their election within six months after the ISO files the results of the relevant Forward Capacity Auction with the Commission. A resource that has had a Permanent De-List Bid or Retirement De-List Bid rejected for reliability reasons and does not notify the ISO of its election as described in this paragraph will be paid on the basis of the resource's Commission-approved Permanent De-List Bid or Commission-approved Retirement De-List Bid. Cost-of-service agreements must be filed with and approved by the Commission, and cost-of-service compensation may not commence until the Commission has approved the use of cost-of-service rates for the unit in question or has accepted the use of the cost-of-service rates subject to refund while the rate is reviewed. In no event will payment under the cost-of-service agreement start prior to the start of the relevant Capacity Commitment Period for which the Permanent De-List Bid or Retirement De-List Bid was submitted. If a resource continues to be needed for reliability in Capacity Commitment Periods following the Capacity Commitment Period for which the Permanent De-List Bid or Retirement De-List Bid was rejected, payment will continue to be pursuant to this Section III.13.2.5.2.5.1(b). Resources that elect payment based on the Commission-approved Permanent De-List Bid or Commission-approved Retirement De-List Bid may file with the Commission pursuant to Section 205 of the Federal Power Act to update its Permanent De-List Bid or Retirement De-List Bid if the unit is retained for reliability for a period longer than the Capacity Commitment Period for which the Permanent De-List Bid or Retirement De-List Bid was originally submitted.

(c) The difference between payments based on resource de-list bids or cost-of-service compensation as detailed in this Section III.13.2.5.2.5.1 and payments based on the market clearing price for the Forward Capacity Market under this Section III.13.2.5.2.5.1 shall be allocated to Regional Network Load within the affected Reliability Region.

(d) **Compensation for Existing Generating Capacity Resources at Stations with Common Costs that are Retained for Reliability**. If a Static De-List Bid, Permanent De-List Bid, or Retirement De-List Bid from an Existing Generating Capacity Resource that is associated with a Station having Common Costs is rejected for reliability reasons, the Existing Generating Capacity Resource will be paid as follows: (i) if one or more Existing Generating Capacity Resources at the Station assume a Capacity Supply Obligation through the normal clearing of the Forward Capacity Auction and one or more Existing Generating Capacity Resources are retained for reliability, then the Existing Generating Capacity Resources retained for reliability will be paid the sum of the Asset-Specific Going Forward Costs for the assets comprising that Existing Generating Capacity Resource; or (ii) if no Existing Generating Capacity Resources at the Station assumes a Capacity Supply Obligation through the normal clearing of the Forward Capacity Auction and one or more Existing Generating Capacity Resources are retained for reliability, then each Existing Generating Capacity Resource retained for reliability will be paid the sum of the Asset-Specific Going Forward Costs for the assets associated with that Existing Generating Capacity Resource plus a portion of the Station Going Forward Common Costs (such that the full amount of Station Going Forward Common Costs are allocated to the Existing Generating Capacity Resources retained for reliability).

(e) If ISO-NE is a party to a cost-of-service agreement filed after January 1, 2019 that changes any resource performance-related obligations contained in Section III, Appendix I (provided that those obligations are different than the obligations of an Existing Generating Capacity Resource with a Capacity Supply Obligation), no later than 30 days after such agreement is filed with the Commission, ISO-NE shall provide to stakeholders quantitative and qualitative information on the need for, and the impacts of, the proposed changes.

III.13.2.5.2.5.2. Incremental Cost of Reliability Service From Permanent De-List Bid or Retirement De-List Bid Resources.

In cases where an Existing Generating Capacity Resource or Existing Demand Capacity Resource has had a Permanent De-List Bid or Retirement De-List Bid for the entire resource rejected for reliability reasons pursuant to Sections III.13.1.2.3.1.5.1 or III.13.2.5.2.5, does not elect to retire pursuant to Section III.13.1.2.3.1.5.1(d), and must make a capital improvement to the unit to remain in operation in order to continue to operate to meet the reliability need identified by the ISO, the resource may make application to the Commission pursuant to Section 205 of the Federal Power Act to receive just and reasonable compensation of the capital investment pursuant to the following:

(a) **Notice to State Utility Commissions, the ISO and Stakeholder Committees of Expectation that a Capital Expense will be Necessary to Meet the Reliability Need Identified by the ISO**: A resource seeking to avail itself of the recovery mechanism provided in this Section must notify the state utility commissions in the states where rate payers will fund the capital improvement, the ISO, and the Participants Committee of its intent to make the capital expenditure and the need for the expenditure. This notification must be made at least 120 days prior to the resource making the capital expenditure.

(b) **Required Showing Made to the Federal Energy Regulatory Commission**: In order to receive just and reasonable compensation for a capital expenditure under this Section, a resource must file an explanation of need with the Commission that explains why the capital expenditure is necessary in order to meet the reliability need identified by the ISO. This showing must demonstrate that the expenditure is reasonably determined to be the least-cost commercially reasonable option consistent with Good Utility Practice to meet the reliability need identified by the ISO. If the resource elects cost-of-service treatment pursuant to Section III.13.2.5.2.5.1(b), the Incremental Cost of Reliability Service filing described in this Section must be made separately from and may be made in advance of the resource's cost-of-service filing.

(c) **Allocation:** Costs of capital expenditures approved by the Commission under this provision shall be allocated to Regional Network Load within the affected Reliability Region.

III.13.2.5.2.5.3. Retirement and Permanent De-Listing of Resources.

(a)(i) A resource, or portion thereof, will be retired coincident with the commencement of the relevant Capacity Commitment Period, or earlier as described in Section III.13.2.5.2.5.3(a)(ii), if the resource: (1) submitted a Retirement De-List Bid at or above the Forward Capacity Auction Starting Price and was not retained for reliability pursuant to Section III.13.1.2.3.1.5.1; (2) submitted a Permanent De-List Bid or Retirement De-List Bid, elected to retire pursuant to Section III.13.1.2.4.1(a), and was not retained for reliability pursuant to Section III.13.1.2.3.1.5.1; (3) elected conditional treatment pursuant to Section III.13.1.2.4.1(b) for a Retirement De-List Bid with a submitted price at or above the Capacity Clearing Price and was not retained for reliability pursuant to Section III.13.1.2.3.1.5.1; or (4) had a Commission-approved Retirement De-List Bid clear in the Forward Capacity Auction. In the case of a Retirement De-List Bid rejected for reliability, if the reliability need that resulted in the rejection for reliability is met, the resource, or portion thereof, will be retired coincident with the end of Capacity Supply Obligation (or earlier as described in Section III.13.2.5.2.5.3(a)(ii)) unless the Commission directs that the obligation to retire be removed or the retirement date extended as part of an Incremental Cost of Reliability Service

filing made pursuant to Section III.13.2.5.2.5.2. The interconnection rights, or relevant portion thereof, for the resource will terminate and the status of the resource, or portion thereof, will be converted to retired on the date of retirement, consistent with the provisions of Schedules 22 and 23 of the OATT.

(a)(ii) A resource, or portion thereof, that is to be retired pursuant to Section III.13.2.5.2.5.3(a)(i) may retire the resource, or portion thereof, earlier than the Capacity Commitment Period for which its Retirement De-List Bid was submitted if it is able to transfer the relevant Capacity Supply Obligation of the resource to another resource through one or more approved Capacity Supply Obligation Bilateral transactions as described in Section III.13.5.1 or reconfiguration auctions as described in Section III.13.4.1. A resource, or portion thereof, electing to retire pursuant to this provision must notify the ISO in writing of its election to retire and the date of retirement. The interconnection rights, or relevant portion thereof, for the resource will terminate and the status of the resource, or portion thereof, will be converted to retired on the date of retirement, consistent with the provisions of Schedules 22 and 23 of the OATT.

(b)(i) A resource, or portion thereof, will be permanently de-listed from the Forward Capacity Market as of the relevant Capacity Commitment Period, or earlier as described in Section III.13.2.5.2.5.3(b)(ii), if the resource: (1) submitted an Internal Market Monitor-approved Permanent De-List Bid at or above the Forward Capacity Auction Starting Price and was not retained for reliablity pursuant to Section III.13.1.2.3.1.5.1; (2) elected conditional treatment pursuant to Section III.13.1.2.4.1(b) for a Permanent De-List Bid with a submitted price at or above the Capacity Clearing Price and was not retained for reliability pursuant to Section III.13.1.2.3.1.5.1; or (3) had a Commission-approved Permanent De-List Bid clear in the Forward Capacity Auction. The CNR Capability interconnection rights, or relevant portion thereof, for the resource will be adjusted downward to reflect the Permanent De-List Bid, consistent with the provisions of Schedules 22 and 23 of the OATT. A resource that permanently de-lists pursuant to this Section III.13.2.5.2.5.3(b)(i) is precluded from subsequent participation in the Forward Capacity Market unless it qualifies as a New Generating Capacity Resource pursuant to Section III.13.1.1.1.2.

(b)(ii) A resource, or portion thereof, that is to be permanently de-listed pursuant to Section III.13.2.5.2.5.3(b)(i) may be permanently de-listed earlier than the Capacity Commitment Period for which its Permanent De-List Bid was submitted if it is able to transfer the entire Capacity Supply Obligation of the resource to another resource through one or more approved Capacity Supply Obligation Bilateral transactions as described in Section III.13.5.1 or reconfiguration auctions as described in Section III.13.4.

(c) A resource that has never been counted as a capacity resource may retire the asset by notifying the ISO in writing of its election to retire and the date of retirement. The date specified for retirement is subject to the limit for resource inactivity set out in Section III.13.2.5.2.5.3(d). The interconnection rights for the resource will terminate and the status of the resource will be converted to retired on the date of retirement.

(d) A resource that does not operate commercially for a period of three calendar years will be deemed by the ISO to be retired. The interconnection rights for the unit will terminate and the status of the unit will be converted to retired on the date of retirement. Where a generator has submitted an application to repower under Schedule 22 or 23 of the OATT, the current interconnection space will be maintained beyond the three years unless the application under Schedule 22 or 23 is withdrawn voluntarily or by the operation of those provisions. Where an application is withdrawn under Schedule 22 or 23, the three year period will be calculated from the last day of commercial operation of the resource.

III.13.2.6. Capacity Rationing Rule.

Except for Dynamic De-List Bids, Export Bids, and offers from New Import Capacity Resources that are subject to rationing pursuant to Section III.13.1.3.5.8 and Existing Import Capacity Resources that are subject to rationing pursuant to Section III.13.1.3.3.A, offers and bids in the Forward Capacity Auction must clear or not clear in whole, unless the offer or bid specifically indicates that it may be rationed. A resource may elect to be rationed to its Rationing Minimum Limit pursuant to Sections III.13.1.1.2.2.3 and III.13.1.2.1.2. Offers from New Import Capacity Resources and Existing Import Capacity Resources will not be rationed where such rationing would violate any applicable physical minimum flow requirements on the associated interface. Export Bids may elect to be rationed generally, but regardless of such election will always be subject to potential rationing where the associated external interface binds. If more Dynamic De-List Bids are submitted at a price than are needed to clear the market, the bids shall be cleared pro-rata, subject to honoring the Rationing Minimum Limit of the resources. Where an offer or bid may be rationed, such rationing may not result in procuring an amount of capacity that is below the associated resource’s Rationing Minimum Limit.

III.13.2.7. Determination of Capacity Clearing Prices.

The Capacity Clearing Price in each Capacity Zone shall be the price established by the descending clock auction as described in Section III.13.2.3, subject to the other provisions of this Section III.13.2.7. The Capacity Clearing Price for the Rest-of-Pool Capacity Zone and the Capacity Clearing Price for each

import-constrained Capacity Zone shall not exceed the Forward Capacity Auction Starting Price. The Capacity Clearing Price for an export-constrained Capacity Zone shall not be less than zero.

III.13.2.7.1. Import-Constrained Capacity Zone Capacity Clearing Price Floor.

The Capacity Clearing Price in an import-constrained Capacity Zone shall not be lower than the Capacity Clearing Price in the Rest-of-Pool Capacity Zone. If after the Forward Capacity Auction is conducted, the Capacity Clearing Price in an import-constrained Capacity Zone is less than the Capacity Clearing Price in the Rest-of-Pool Capacity Zone, all resources clearing in the import-constrained Capacity Zone shall be paid based on the Capacity Clearing Price in the Rest-of-Pool Capacity Zone during the associated Capacity Commitment Period.

III.13.2.7.2. Export-Constrained Capacity Zone Capacity Clearing Price Ceiling.

The Capacity Clearing Price in an export-constrained Capacity Zone shall not be higher than the Capacity Clearing Price in the Rest-of-Pool Capacity Zone.

The Capacity Clearing Price in a nested Capacity Zone shall not be higher than the Capacity Clearing Price in the Capacity Zone within which it is located.

III.13.2.7.3. [Reserved.]

III.13.2.7.3A. Treatment of Imports.

At the Capacity Clearing Price, if the amount of capacity offered from New Import Capacity Resources and Existing Import Capacity Resources over an interface between an external Control Area and the New England Control Area is greater than that interface's approved capacity transfer limit (net of tie benefits, or net of HQICC in the case of the Phase I/II HVDC-TF):

> (a) the full amount of capacity offered at that price from Existing Import Capacity Resources associated with contracts listed in Section III.13.1.3.3.A(c) shall clear, unless that amount of capacity is greater than the interface's approved capacity transfer limit (net of tie benefits, or net of HQICC in the case of the Phase I/II HVDC-TF), in which case the capacity offered at that price from Existing Import Capacity Resources associated with contracts listed in Section III.13.1.3.3.A(c) shall be rationed such that the interface's approved capacity transfer limit (net of tie benefits, or net of HQICC in the case of the Phase I/II HVDC-TF) is not exceeded; and

(b) if there is space remaining over the interface after the allocation described in subsection (a) above, then the capacity offered at that price from New Import Capacity Resources and Existing Import Capacity Resources other than Existing Import Capacity Resources associated with the contracts listed in Section III.13.1.3.3.A(c) will be rationed such that the interface's approved capacity transfer limit (net of tie benefits, or net of HQICC in the case of the Phase I/II HVDC-TF) is not exceeded. If the capacity offered at that price by any single New Import Capacity Resource or Existing Import Capacity Resource that is not associated with the contracts listed in Section III.13.1.3.3.A(c) is greater than the interface's approved capacity transfer limit (net of tie benefits, or net of HQICC in the case of the Phase I/II HVDC-TF), then the capacity offered by that resource that is above the interface's approved capacity transfer limit (net of tie benefits, or net of HQICC in the case of the Phase I/II HVDC-TF) shall not be included in the rationing.

III.13.2.7.4. Effect of Capacity Rationing Rule on Capacity Clearing Price.

Where the requirement that offers and bids clear or not clear in whole (Section III.13.2.6) prohibits the descending clock auction in its normal progression from clearing one or more Capacity Zones at the precise amount of capacity determined by the Capacity Zone Demand Curves specified in Section III.13.2.2, then the auctioneer shall analyze the aggregate supply curve to determine cleared capacity offers and Capacity Clearing Prices that seek to maximize social surplus for the associated Capacity Commitment Period. The clearing algorithm may result in offers below the Capacity Clearing Price not clearing, and in de-list bids below the Capacity Clearing Price clearing.

III.13.2.7.5. Effect of Decremental Repowerings on the Capacity Clearing Price.

Where the effect of accounting for certain repowering offers and bids (as described in Section III.13.2.3.2(e)) results in the auction not clearing at the lowest price for the required quantity of capacity, then the auctioneer will conduct additional auction rounds of the Forward Capacity Auction as necessary to minimize capacity costs.

III.13.2.7.6. Minimum Capacity Award.

Each offer (excluding offers from Conditional Qualified New Resources that do not satisfy the conditions specified in Sections III.13.2.5.1(i)-(iii)) clearing in the Forward Capacity Auction shall be awarded a Capacity Supply Obligation at least as great as the amount of capacity offered at the End-of-Round Price in the final round of the Forward Capacity Auction. For Intermittent Power Resources, the Capacity

Supply Obligation for months in the winter period (as described in Section III.13.1.5) shall be adjusted based on its winter Qualified Capacity as determined pursuant to Section III.13.1.1.2.2.6 and Section III.13.1.2.2.2.

III.13.2.7.7. Tie-Breaking Rules.

Where the provisions in this Section III.13.2 for clearing the Forward Capacity Auction (system-wide or in a single Capacity Zone) result in a tie – that is, where two or more resources offer sufficient capacity at prices that would clear the auction at the same minimum costs – the auctioneer shall apply the following rules (in sequence, as necessary) to determine clearing:

(a) [Reserved.]

(b) If multiple projects may be rationed, they will be rationed proportionately.

(c) Where clearing either the offer associated with a resource with a higher queue priority at a Conditional Qualified New Resource's location or the offer associated with the Conditional Qualified New Resource would result in equal costs, the offer associated with the resource with the higher queue priority shall clear.

(d) The offer associated with the Project Sponsor having the lower market share in the capacity auction (including Existing Generating Capacity Resources, Existing Import Capacity Resources, and Existing Demand Capacity Resources) shall be cleared.

III.13.2.8. Capacity Substitution Auctions.

III.13.2.8.1. Administration of Substitution Auctions.

Following the completion of the primary auction-clearing process of the Forward Capacity Auction as provided for in Section III.13.2, the ISO shall conduct a substitution auction, using a static double auction to clear supply offers (offers to assume a Capacity Supply Obligation) and demand bids (bids to shed a Capacity Supply Obligation). Supply offers and demand bids will be modeled in the Capacity Zone where the associated resources are electrically interconnected.

III.13.2.8.1.1. Substitution Auction Clearing and Awards.

The substitution auction shall maximize total social surplus as specified by the demand bids and supply offers used in the auction. The maximization is constrained as follows:

(i) By the external interface limits modeled in the primary auction-clearing process.

(ii) Such that the net cleared Capacity Supply Obligations (total acquired less total shed) in the substitution auction is equal to zero.

(iii) Such that, for each import-constrained Capacity Zone, if the zone's total Capacity Supply Obligations awarded in the primary auction-clearing process of the Forward Capacity Auction is less than the zone threshold quantity specified below, then the zone's net cleared Capacity Supply Obligations (total acquired less total shed) in the substitution auction is equal to zero; otherwise, the sum of the zone's total Capacity Supply Obligations awarded in the primary auction-clearing process and the zone's net cleared Capacity Supply Obligations (total acquired less total shed) in the substitution auction is greater than or equal to the zone threshold quantity specified below.

(iv) Such that, for each export-constrained Capacity Zone, if the zone's total Capacity Supply Obligations awarded in the primary auction-clearing process of the Forward Capacity Auction is greater than the zone threshold quantity specified below, then the zone's net cleared Capacity Supply Obligations (total acquired less total shed) in the substitution auction is equal to zero; otherwise, the sum of the zone's total Capacity Supply Obligations awarded in the primary auction-clearing process and the zone's net cleared Capacity Supply Obligations (total acquired less total shed) in the substitution auction is less than or equal to the zone threshold quantity specified below.

In applying constraint (iii), the zone threshold quantity for an import-constrained Capacity Zone shall be equal to the sum of its Capacity Zone Demand Curve truncation point quantity specified in Section III.13.2.2.2 and the total quantity of any Export Bids and any Administrative Export De-List Bids for which the exporting resource is located outside the import-constrained Capacity Zone, that are used to export capacity across an external interface connected to the import-constrained Capacity Zone, and that cleared in the primary auction-clearing process of the Forward Capacity Auction.

In applying constraint (iv), the zone threshold quantity for an export-constrained Capacity Zone shall be equal to its Capacity Zone Demand Curve truncation point quantity specified in Section III.13.2.2.3 less the total quantity of any Export Bids and any Administrative Export De-List Bids for which the exporting resource is located in the export-constrained Capacity Zone, including any Export Bids and any Administrative Export De-List Bids in an associated nested export-constrained Capacity Zone, that are

used to export capacity across an external interface connected to another Capacity Zone, and that cleared in the primary auction-clearing process of the Forward Capacity Auction.

In applying constraints (iii) and (iv), a zone's total Capacity Supply Obligations awarded in the primary auction-clearing process of the Forward Capacity Auction and net cleared Capacity Supply Obligations (total acquired less total shed) in the substitution auction shall include the Capacity Supply Obligations of Import Capacity Resources at each external interface connected to the Capacity Zone.

In applying constraints (iii) and (iv), a zone's total Capacity Supply Obligations awarded in the primary auction-clearing process of the Forward Capacity Auction shall include the Capacity Supply Obligations awarded to Proxy De-List Bids within the zone, and the zone's net cleared Capacity Supply Obligations (total acquired less total shed) in the substitution auction shall include the Capacity Supply Obligations shed from demand bids associated with Proxy De-List Bids within the zone.

In cases in which there are multiple clearing outcomes that would each maximize the substitution auction's objective, the following tie-breaking rules will apply in the following sequence: (i) non-rationable demand bids associated with Lead Market Participants having the largest total FCA Qualified Capacity of Existing Capacity Resources will be cleared first; and (ii) rationable supply offers will be cleared in proportion to their offer quantity.

For Intermittent Power Resources, other than those participating as the summer resource in a Composite FCM Transaction, the cleared award for supply offers and demand bids shall be adjusted for the months in the winter period (as described in Section III.13.1.5) using the ratio of the resource's cleared offer or bid amount divided by its FCA Qualified Capacity multiplied by its winter Qualified Capacity as determined pursuant to Section III.13.1.1.2.2.6 and Section III.13.1.2.2.2 after removing any portion of the resource's winter Qualified Capacity that is participating in a Composite FCM Transaction.

The cleared offer amount awarded to a Composite FCM Transaction in the substitution auction will be assigned to the summer and winter resources for their respective obligation months during the Capacity Commitment Period as described in Section III.13.1.5.

If, after the substitution auction, a resource has a Capacity Supply Obligation below its Economic Minimum Limit, it must meet the requirements of Section III.13.6.1.1.1.

III.13.2.8.1.2. Substitution Auction Pricing.

The substitution auction will specify clearing prices for Capacity Zones and external interfaces as follows.

For each import-constrained Capacity Zone, if the sum of the zone's total Capacity Supply Obligations awarded in the primary auction-clearing process of the Forward Capacity Auction and the zone's net cleared Capacity Supply Obligations (total acquired less total shed) in the substitution auction is greater than its zone threshold quantity specified in Section III.13.2.8.1.1, then supply offers and demand bids in the substitution auction in the import-constrained Capacity Zone shall be treated as offers and bids in the Rest-of-Pool Capacity Zone for purposes of determining substitution auction clearing prices.

For each export-constrained Capacity Zone,

(i) if the sum of the zone's total Capacity Supply Obligations, including Capacity Supply Obligations in a nested Capacity Zone, awarded in the primary auction-clearing process of the Forward Capacity Auction and the zone's net cleared Capacity Supply Obligations (total acquired less total shed) in the substitution auction including net cleared Capacity Supply Obligations in the nested Capacity Zone is less than its zone threshold quantity specified in Section III.13.2.8.1.1, then supply offers and demand bids in the substitution auction in the export-constrained Capacity Zone (excluding supply offers and demand bids in the nested Capacity Zone that are not treated as offers and bids in the export-constrained Capacity Zone pursuant to Section III.13.2.8.1.2(ii)) shall be treated as offers and bids in the Rest-of-Pool Capacity Zone for purposes of determining substitution auction clearing prices.

(ii) if the sum of a nested Capacity Zone's Capacity Supply Obligations awarded in the primary auction-clearing process of the Forward Capacity Auction and the nested Capacity Zone's net cleared Capacity Supply Obligations (total acquired less total shed) in the substitution auction is less than its zone threshold quantity specified in Section III.13.2.8.1.1, then supply offers and demand bids in the substitution auction in the nested Capacity Zone shall be treated as offers and bids in the export-constrained Capacity Zone within which the nested Capacity Zone is located, for purposes of determining substitution auction clearing prices.

The substitution auction clearing prices for the Rest-of-Pool Capacity Zone and for any constrained zones pooled with the Rest-of-Pool Capacity Zone for pricing purposes shall be determined by the price of the

demand bid or supply offer that is marginal. If a demand bid associated with a Proxy De-List Bid is marginal, then the substitution auction clearing prices shall be set equal to the Capacity Clearing Prices.

The substitution auction clearing price for a constrained Capacity Zone that is not pooled with the Rest-of-Pool Capacity Zone for pricing purposes shall be determined by the price of the demand bid or supply offer associated with the separately-priced constrained Capacity Zone that is marginal. If a demand bid associated with a Proxy De-List Bid is marginal, then the substitution auction clearing price shall be set equal to the Capacity Clearing Price for the constrained Capacity Zone.

The substitution auction clearing price for a nested export-constrained Capacity Zone that is not pooled with the export-constrained Capacity Zone in which it is located for pricing purposes shall be determined by the price of the demand bid or supply offer that is marginal in the nested export-constrained Capacity Zone. If a demand bid associated with a Proxy De-List Bid is marginal, then the substitution auction clearing price for the nested export-constrained Capacity Zone shall be equal to the Capacity Clearing Price for that nested export-constrained Capacity Zone.

If the net quantity of Capacity Supply Obligations awarded in the primary Forward Capacity Auction and substitution auction over an interface between the New England Control Area and an external Control Area is less than that interface's approved capacity transfer limit (net of tie benefits, or net of HQICC in the case of the Phase I/II HVDC-TF), then supply offers and demand bids in the substitution auction at the interface shall be treated as offers and bids in the modeled Capacity Zone associated with that interface for purposes of determining substitution auction clearing prices.

If the net quantity of Capacity Supply Obligations awarded in the primary Forward Capacity Auction and substitution auction over an interface between the New England Control Area and an external Control Area is equal to that interface's approved capacity transfer limit (net of tie benefits, or net of HQICC in the case of the Phase I/II HVDC-TF), then the substitution auction clearing price for that interface will be determined by the demand bid or supply offer that is marginal at that interface. If a cleared demand bid associated with a Proxy De-List Bid is marginal at the external interface, then the substitution auction clearing price for that interface shall be set equal to the Capacity Clearing Price for that interface.

The substitution auction clearing price for an import-constrained Capacity Zone where the total Capacity Supply Obligations awarded in the primary action-clearing process of the Forward Capacity Auction are greater than or equal to the zone's threshold quantity specified in Section III.13.2.8.1.1 shall not be lower

than the substitution auction clearing price for the Rest-of-Pool Capacity Zone.

The substitution auction clearing price for an export-constrained Capacity Zone that is not a nested export-constrained Capacity Zone, where the total Capacity Supply Obligations awarded in the primary auction-clearing process of the Forward Capacity Auction are less than or equal to the zone's threshold quantity specified in Section III.13.2.8.1.1 shall not exceed the substitution auction clearing price for the Rest-of-Pool Capacity Zone.

The substitution auction clearing price for a nested export-constrained Capacity Zone where the total Capacity Supply Obligations awarded in the primary auction-clearing process of the Forward Capacity Auction are less than or equal to the zone's threshold quantity specified in Section III.13.2.8.1.1 shall not exceed the substitution auction clearing price for the Capacity Zone within which it is located.

The substitution auction clearing price at an external interface shall not exceed the substitution auction clearing price in the Capacity Zone connected to the external interface.

If, pursuant to the rules specified above, the substitution auction clearing price for any Capacity Zone or external interface would exceed the Capacity Clearing Price for that location, the substitution auction clearing price for that location only is set equal to its Capacity Clearing Price.

The substitution auction clearing price for any Capacity Zone or external interface cannot be less than negative one multiplied by the Forward Capacity Auction Starting Price.

III.13.2.8.2. Supply Offers in the Substitution Auction.

III.13.2.8.2.1. Supply Offers.

To participate as supply in the substitution auction, a Project Sponsor for a New Capacity Resource must meet the following criteria:

(a) The Project Sponsor and the New Capacity Resource must meet all the requirements for participation in the Forward Capacity Auction specified in Section III.13.1.

(b) The Project Sponsor must elect to have the resource participate in the substitution auction during the New Capacity Show of Interest Window. Pursuant to an election, the resource's total amount of FCA Qualified Capacity that qualifies as a New Capacity Resource will be obligated to

participate in the substitution auction, including any capacity of a Renewable Technology Resource that was not qualified due to proration pursuant to Section III.13.1.1.2.10(a), and subject to the other provisions of this Section III.13.2.8.2.

(c) The Project Sponsor must certify that the New Capacity Resource is a Sponsored Policy Resource as part of the submission of the New Capacity Qualification Package.

Substitution auction supply offers are rationable.

A resource participating in the Forward Capacity Auction as a New Generating Capacity Resource pursuant to Section III.13.1.1.1.2 (resources previously counted as capacity resources) is not eligible to participate as supply in the substitution auction. A resource is not eligible to participate as supply in the substitution auction if it has submitted a demand bid for the substitution auction.

A Composite FCM Transaction comprised of a summer resource that is a Sponsored Policy Resource is eligible to participate as supply in the substitution auction.

A Conditional Qualified New Resource may participate in the substitution auction provided that the resource with which it has overlapping interconnection impacts: (i) did not receive a Capacity Supply Obligation, fully or partially, in the primary auction-clearing process, and: (ii) is not eligible to participate in the substitution auction. A resource having a higher priority in the queue than a Conditional Qualified New Resource with which it has overlapping interconnection impact may participate in the substitution auction provided that the Conditional Qualified New Resource did not receive a Capacity Supply Obligation, fully or partially, in the primary auction-clearing process.

III.13.2.8.2.2. Supply Offer Prices.

Project Sponsors must submit substitution auction supply offer prices no later than five Business Days after the deadline for submission of offers composed of separate resources.

A substitution auction supply offer must be in the form of a curve (with up to five price-quantity pairs). The curve may not decrease in quantity as the price increases. A supply offer price for the substitution auction may not be greater than the Forward Capacity Auction Starting Price or lower than negative one multiplied by the Forward Capacity Auction Starting Price.

If the offer quantity does not equal the resource's FCA Qualified Capacity, the quantity for which no offer price was submitted will be assigned a price equal to the Forward Capacity Auction Starting Price.

III.13.2.8.2.3. Supply Offers Entered into the Substitution Auction

Supply offers for resources that satisfy all of the criteria in Section III.13.2.8.2.1 to participate in the substitution auction may be adjusted prior to conducting the substitution auction-clearing process using the following adjustments:

(a) Any portion of a resource's FCA Qualified Capacity that was cleared (received a Capacity Supply Obligation) in the primary auction-clearing process will be removed from the resource's substitution auction supply offer beginning with the lowest priced price-quantity pairs.

(b) After performing the adjustment specified in Section III.13.2.8.2.3(a), any price-quantity pairs in a resource's substitution auction supply offer with a price greater than the Capacity Clearing Price for the resource's Capacity Zone or external interface are removed from the offer.

III.13.2.8.3. Demand Bids in the Substitution Auction.

III.13.2.8.3.1. Demand Bids.

Market Participants with Existing Generating Capacity Resources or Existing Import Capacity Resources associated with External Elective Transmission Upgrades may elect to submit demand bids for the substitution auction for those resources by the Existing Capacity Retirement Deadline. The election must specify the total amount of the resource's Qualified Capacity that will be associated with its demand bid.

A resource, including any portion of an existing resource that qualifies as a New Capacity Resource, must have achieved FCM Commercial Operation no later than seven days after the issuance by the ISO of the qualification determination notification described in Section III.13.1.2.4(b) in order to participate as demand in the substitution auction.

Regardless of whether an election is made, a demand bid is required for any portion of a resource that is associated with a Retirement De-List Bid, provided that the entire resource has achieved FCM Commercial Operation no later than seven days after the issuance by the ISO of the qualification determination notification described in Section III.13.1.2.4(b).

A resource for which a demand bid election has been made cannot participate in a Composite FCM Transaction, cannot be designated as a Self-Supplied FCA Resource, and will not have incremental summer or winter capacity that does not span the entire Capacity Commitment Period subjected to the treatment specified in Section III.13.1.1.1.3.A.

Demand bids are non-rationable.

A demand bid will be entered into the substitution auction for the portion of the resource that receives a Capacity Supply Obligation in the primary auction-clearing process, subject to the other provisions of this Section III.13.2.8.3. A resource, or portion thereof, associated with a cleared demand bid shall be retired from all New England Markets at the start of the Capacity Commitment Period associated with the Forward Capacity Auction.

III.13.2.8.3.1A Substitution Auction Test Prices.

(a) **Participant-Submitted Test Price.** For auctions associated with a Capacity Commitment Period that begins on or after June 1, 2023, Market Participants that submit a substitution auction demand bid must submit a test price, calculated using the method described below, by the Existing Capacity Retirement Deadline.

The test price for the capacity associated with a resource's demand bid must be calculated using the same methodology as a Retirement De-List Bid, except that a Market Participant may not submit test prices for multiple price-quantity segments but must submit a single test price using, as necessary, aggregated cost and revenue data. The test price must be accompanied by the same documentation required for Retirement De-List Bids above the Dynamic De-List Bid Threshold pursuant to Section III.13.1.2.3.2.1. A Market Participant must submit a test price regardless of whether the price is below the Dynamic De-List Bid Threshold.

A Market Participant is not required to submit a test price for any resource for which the demand bid is less than 3 MW. The applicable test price for any such resource is $0.00/kW-month.

(b) **IMM-Determined Test Price.** The Internal Market Monitor shall review each test price submission using the methodology specified in Section III.13.1.2.3.2.1 for evaluating Retirement De-List Bids, regardless of whether the submitted test price is below the Dynamic De-List Bid Threshold. For purposes of this review, the expected revenues for a cleared substitution auction demand bid shall not be

included as a component of opportunity costs. After due consideration and consultation with the Market Participant, as appropriate, the Internal Market Monitor shall replace the submitted test price with an IMM-determined test price if the submitted test price is not consistent with the sum of the net present value of the resource's expected cash flows plus reasonable expectations about the resource's Capacity Performance Payments plus reasonable opportunity costs.

The Internal Market Monitor's determination regarding a Market Participant-submitted test price shall be included in the retirement determination notification described in Section III.13.1.2.4(a) and in the filing made to the Commission as described in Section III.13.8.1(a).

The test price used for purposes of the substitution auction shall be the Market Participant-submitted test price, as adjusted by the Internal Market Monitor pursuant to this Section III.13.2.8.3.1A(b), and as further adjusted by the Commission in response to the Internal Market Monitor's filing pursuant to Section III.13.1.2.4(a).

III.13.2.8.3.2. Demand Bid Prices.

Market Participants must submit substitution auction demand bid prices no later than five Business Days after the deadline for submission of offers composed of separate resources.

A substitution auction demand bid must be in the form of a curve (with up to five price-quantity pairs). The curve may not decrease in quantity as the price decreases. A demand bid price for the substitution auction may not be greater than the Forward Capacity Auction Starting Price or lower than negative one multiplied by the Forward Capacity Auction Starting Price.

If the bid quantity does not equal the total bid amount submitted by the Market Participant or required for a Retirement De-List Bid pursuant to Section III.13.2.8.3.1, the quantity for which no bid price was specified will be assigned a price equal to negative one multiplied by the Forward Capacity Auction Starting Price.

For auctions associated with a Capacity Commitment Period that begins on or after June 1, 2023, Market Participants may elect either of the demand bid adjustment methods specified in Section III.13.2.8.3.3(b) for the resource by no later than five Business Days after the deadline for submission of offers composed of separate resources. If no such election is made, the adjustment applied shall be the method specified in Section III.13.2.8.3.3(b)(i).

III.13.2.8.3.3. Demand Bids Entered into the Substitution Auction.

If a resource is determined to be needed for reliability pursuant to Section III.13.2.5.2.5, then any demand bid associated with the resource will not be further included in the substitution auction. If a resource is awarded a Capacity Supply Obligation in the primary auction-clearing process and the Capacity Clearing Price is less than ninety percent of the resource's test price as established pursuant to Section III.13.2.8.3.1A, then the resource's demand bid will not be included in the substitution auction.

Demand bids for resources that satisfy all of the criteria in Section III.13.2.8.3.1 to participate in the substitution auction will be adjusted prior to conducting the substitution auction-clearing process using the following adjustments:

(a) For the substitution auction associated with the Capacity Commitment Period beginning on June 1, 2022, any portion of a resource's demand bid that exceeds its Capacity Supply Obligation awarded in the primary auction-clearing process will be removed from the substitution auction demand bid beginning with the highest priced price-quantity pairs.

(b) For substitution auctions associated with a Capacity Commitment Period that begins on or after June 1, 2023, a resource's demand bid will be adjusted using one of the following methods as elected pursuant to Section III.13.2.8.3.2:

(i) The portion of a resource's capacity that did not receive a Capacity Supply Obligation in the primary auction-clearing process will be removed from the substitution auction demand bid beginning with the highest priced price-quantity pair.

(ii) Any portion of a resource's demand bid that exceeds its Capacity Supply Obligation awarded in the primary auction-clearing process will be removed from the substitution auction demand bid beginning with the lowest priced price-quantity pair.

(c) After performing the modification specified in Sections III.13.2.8.3.3(a) or III.13.2.8.3.3(b), any price-quantity pairs in a resource's substitution auction demand bid with a price greater than the Capacity Clearing Price for the resource's Capacity Zone or external interface will have its price reduced to the Capacity Clearing Price for the resource's Capacity Zone or external interface.

Except as provided in Section III.13.2.5.2.1(c), a rationable demand bid will be entered into the substitution auction on behalf of any Proxy De-List Bid associated with a Permanent De-List Bid or

Retirement De-List Bid. The demand bid quantity will equal the portion of the Proxy De-List Bid that was not cleared (received a Capacity Supply Obligation) in the first run of the primary auction-clearing process. The demand bid will have priority to clear before non-rationable demand bids.

SECTION III

MARKET RULE 1

APPENDIX A

MARKET MONITORING,
REPORTING AND MARKET POWER MITIGATION

APPENDIX A

MARKET MONITORING, REPORTING AND MARKET POWER MITIGATION

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MARKET MONITORING, REPORTING AND MARKET POWER MITIGATION

III.A.1. Introduction and Purpose; Structure and Oversight: Independence.

III.A.1.1. Mission Statement.

The mission of the Internal Market Monitor and External Market Monitor shall be (1) to protect both consumers and Market Participants by the identification and reporting of market design flaws and market power abuses; (2) to evaluate existing and proposed market rules, tariff provisions and market design elements to remove or prevent market design flaws and recommend proposed rule and tariff changes to the ISO; (3) to review and report on the performance of the New England Markets; (4) to identify and notify the Commission of instances in which a Market Participant's behavior, or that of the ISO, may require investigation; and (5) to carry out the mitigation functions set forth in this ***Appendix A.***

III.A.1.2. Structure and Oversight.

The market monitoring and mitigation functions contained in this ***Appendix A*** shall be performed by the Internal Market Monitor, which shall report to the ISO Board of Directors and, for administrative purposes only, to the ISO Chief Executive Officer, and by an External Market Monitor selected by and reporting to the ISO Board of Directors. Members of the ISO Board of Directors who also perform management functions for the ISO shall be excluded from oversight and governance of the Internal Market Monitor and External Market Monitor. The ISO shall enter into a contract with the External Market Monitor addressing the roles and responsibilities of the External Market Monitor as detailed in this ***Appendix A***. The ISO shall file its contract with the External Market Monitor with the Commission. In order to facilitate the performance of the External Market Monitor's functions, the External Market Monitor shall have, and the ISO's contract with the External Market Monitor shall provide for, access by the External Market Monitor to ISO data and personnel, including ISO management responsible for market monitoring, operations and billing and settlement functions. Any proposed termination of the contract with the External Market Monitor or modification of, or other limitation on, the External Market Monitor's scope of work shall be subject to prior Commission approval.

III.A.1.3. Data Access and Information Sharing.

The ISO shall provide the Internal Market Monitor and External Market Monitor with access to all market data, resources and personnel sufficient to enable the Internal Market Monitor and External Market Monitor to perform the market monitoring and mitigation functions provided for in this ***Appendix A***.

This access shall include access to any confidential market information that the ISO receives from another independent system operator or regional transmission organization subject to the Commission's jurisdiction, or its market monitor, as part of an investigation to determine (a) if a Market Violation is occurring or has occurred, (b) if market power is being or has been exercised, or (c) if a market design flaw exists. In addition, the Internal Market Monitor and External Market Monitor shall have full access to the ISO's electronically generated information and databases and shall have exclusive control over any data created by the Internal Market Monitor or External Market Monitor. The Internal Market Monitor and External Market Monitor may share any data created by it with the ISO, which shall maintain the confidentiality of such data in accordance with the terms of the ISO New England Information Policy.

III.A.1.4. Interpretation.

In the event that any provision of any ISO New England Filed Document is inconsistent with the provisions of this ***Appendix A***, the provisions of ***Appendix A*** shall control. Notwithstanding the foregoing, Sections III.A.1.2, III.A.2.2 (a)-(c), (e)-(h), Section III.A.2.3 (a)-(g), (i), (n) and Section III.A.17.3 are also part of the Participants Agreement and cannot be modified in either ***Appendix A*** or the Participants Agreement without a corresponding modification at the same time to the same language in the other document.

III.A.1.5. Definitions.

Capitalized terms not defined in this ***Appendix A*** are defined in the definitions section of Section I of the Tariff.

III.A.2. Functions of the Market Monitor.

III.A.2.1. Core Functions of the Internal Market Monitor and External Market Monitor.

The Internal Market Monitor and External Market Monitor will perform the following core functions:

(a) Evaluate existing and proposed market rules, tariff provisions and market design elements, and recommend proposed rule and tariff changes to the ISO, the Commission, Market Participants, public utility commissioners of the six New England states, and to other interested entities, with the understanding that the Internal Market Monitor and External Market Monitor are not to effectuate any proposed market designs (except as specifically provided in Section III.A.2.4.4, Section III.A.9 and Section III.A.10 of this ***Appendix A***). In the event the Internal Market Monitor or External Market Monitor believes broader dissemination could lead to exploitation, it shall limit distribution of its

identifications and recommendations to the ISO and to the Commission, with an explanation of why broader dissemination should be avoided at that time. Nothing in this Section III.A.2.1 (a) shall prohibit or restrict the Internal Market Monitor and External Market Monitor from implementing Commission accepted rule and tariff provisions regarding market monitoring or mitigation functions that, according to the terms of the applicable rule or tariff language, are to be performed by the Internal Market Monitor or External Market Monitor.

(b) Review and report on the performance of the New England Markets to the ISO, the Commission, Market Participants, the public utility commissioners of the six New England states, and to other interested entities.

(c) Identify and notify the Commission's Office of Enforcement of instances in which a Market Participant's behavior, or that of the ISO, may require investigation, including suspected tariff violations, suspected violations of Commission-approved rules and regulations, suspected market manipulation, and inappropriate dispatch that creates substantial concerns regarding unnecessary market inefficiencies.

III.A.2.2. Functions of the External Market Monitor.

To accomplish the functions specified in Section III.A.2.1 of this ***Appendix A***, the External Market Monitor shall perform the following functions:

(a) Review the competitiveness of the New England Markets, the impact that the market rules and/or changes to the market rules will have on the New England Markets and the impact that the ISO's actions have had on the New England Markets. In the event that the External Market Monitor uncovers problems with the New England Markets, the External Market Monitor shall promptly inform the Commission, the Commission's Office of Energy Market Regulation staff, the ISO Board of Directors, the public utility commissions for each of the six New England states, and the Market Participants of its findings in accordance with the procedures outlined in Sections III.A.19 and III.A.20 of this ***Appendix A***, provided that in the case of Market Participants and the public utility commissions, information in such findings shall be redacted as necessary to comply with the ISO New England Information Policy. Notwithstanding the foregoing, in the event the External Market Monitor believes broader dissemination could lead to exploitation, it shall limit distribution of its identifications to the ISO and to the Commission, with an explanation of why broader dissemination should be avoided at that time.

(b) Perform independent evaluations and prepare annual and ad hoc reports on the overall competitiveness and efficiency of the New England Markets or particular aspects of the New England

Markets, including the adequacy of this ***Appendix A***, in accordance with the provisions of Section III.A.17 of this ***Appendix A***.

(c) Conduct evaluations and prepare reports on its own initiative or at the request of others.

(d) Monitor and review the quality and appropriateness of the mitigation conducted by the Internal Market Monitor. In the event that the External Market Monitor discovers problems with the quality or appropriateness of such mitigation, the External Market Monitor shall promptly inform the Commission, the Commission's Office of Energy Market Regulation staff, the ISO Board of Directors, the public utility commissions for each of the six New England states, and the Market Participants of its findings in accordance with the procedures outlined in Sections III.A.19 and/or III.A.20 of this ***Appendix A,*** provided that in the case of Market Participants and the public utility commissions, information in such findings shall be redacted as necessary to comply with the ISO New England Information Policy. Notwithstanding the foregoing, in the event the External Market Monitor believes broader dissemination could lead to exploitation, it shall limit distribution of its identifications to the ISO and to the Commission, with an explanation of why broader dissemination should be avoided at that time.

(e) Prepare recommendations to the ISO Board of Directors and the Market Participants on how to improve the overall competitiveness and efficiency of the New England Markets or particular aspects of the New England Markets, including improvements to this ***Appendix A***.

(f) Recommend actions to the ISO Board of Directors and the Market Participants to increase liquidity and efficient trade between regions and improve the efficiency of the New England Markets.

(g) Review the ISO's filings with the Commission from the standpoint of the effects of any such filing on the competitiveness and efficiency of the New England Markets. The External Market Monitor will have the opportunity to comment on any filings under development by the ISO and may file comments with the Commission when the filings are made by the ISO. The subject of any such comments will be the External Market Monitor's assessment of the effects of any proposed filing on the competitiveness and efficiency of the New England Markets, or the effectiveness of this ***Appendix A***, as appropriate.

(h) Provide information to be directly included in the monthly market updates that are provided at the meetings of the Market Participants.

III.A.2.3. Functions of the Internal Market Monitor.

To accomplish the functions specified in Section III.A.2.1 of this ***Appendix A***, the Internal Market Monitor shall perform the following functions:

(a) Maintain ***Appendix A*** and consider whether ***Appendix A*** requires amendment. Any amendments deemed to be necessary by the Internal Market Monitor shall be undertaken after consultation with Market Participants in accordance with Section 11 of the Participants Agreement.

(b) Perform the day-to-day, real-time review of market behavior in accordance with the provisions of this ***Appendix A***.

(c) Consult with the External Market Monitor, as needed, with respect to implementing and applying the provisions of this ***Appendix A.***

(d) Identify and notify the Commission's Office of Enforcement staff of instances in which a Market Participant's behavior, or that of the ISO, may require investigation, including suspected Tariff violations, suspected violations of Commission-approved rules and regulations, suspected market manipulation, and inappropriate dispatch that creates substantial concerns regarding unnecessary market inefficiencies, in accordance with the procedures outlined in Section III.A.19 of this ***Appendix A.***

(e) Review the competitiveness of the New England Markets, the impact that the market rules and/or changes to the market rules will have on the New England Markets and the impact that ISO's actions have had on the New England Markets. In the event that the Internal Market Monitor uncovers problems with the New England Markets, the Internal Market Monitor shall promptly inform the Commission, the Commission's Office of Energy Market Regulation staff, the ISO Board of Directors, the public utility commissions for each of the six New England states, and the Market Participants of its findings in accordance with the procedures outlined in Sections III.A.19 and III.A.20 of this ***Appendix A***, provided that in the case of Market Participants and the public utility commissions, information in such findings shall be redacted as necessary to comply with the ISO New England Information Policy. Notwithstanding the foregoing, in the event the Internal Market Monitor believes broader dissemination could lead to exploitation, it shall limit distribution of its identifications to the ISO and to the Commission, with an explanation of why broader dissemination should be avoided at that time.

(f) Provide support and information to the ISO Board of Directors and the External Market Monitor consistent with the Internal Market Monitor's functions.

(g) Prepare an annual state of the market report on market trends and the performance of the New England Markets, as well as less extensive quarterly reports, in accordance with the provisions of Section III.A.17 of this ***Appendix A***.

(h) Make one or more of the Internal Market Monitor staff members available for regular conference calls, which may be attended, telephonically or in person, by Commission and state commission staff, by representatives of the ISO, and by Market Participants. The information to be provided in the

Internal Market Monitor conference calls is generally to consist of a review of market data and analyses of the type regularly gathered and prepared by the Internal Market Monitor in the course of its business, subject to appropriate confidentiality restrictions. This function may be performed through making a staff member of the Internal Market Monitor available for the monthly meetings of the Market Participants and inviting Commission staff and the staff of state public utility commissions to those monthly meetings.

(i) Be primarily responsible for interaction with external Control Areas, the Commission, other regulators and Market Participants with respect to the matters addressed in this ***Appendix A***.

(j) Monitor for conduct whether by a single Market Participant or by multiple Market Participants acting in concert, including actions involving more than one Resource, that may cause a material effect on prices or other payments in the New England Markets if exercised from a position of market power, and impose appropriate mitigation measures if such conduct is detected and the other applicable conditions for the imposition of mitigation measures as set forth in this ***Appendix A*** are met. The categories of conduct for which the Internal Market Monitor shall perform monitoring for potential mitigation are:

(i) *Economic withholding*, that is, submitting a Supply Offer for a Resource that is unjustifiably high and violates the economic withholding criteria set forth in Section III.A.5 so that (i) the Resource is not or will not be dispatched or scheduled, or (ii) the bid or offer will set an unjustifiably high market clearing price.

(ii) *Uneconomic production from a Resource*, that is, increasing the output of a Resource to levels that would otherwise be uneconomic, absent an order of the ISO, in order to cause, and obtain benefits from, a transmission constraint.

(iii) *Anti-competitive Increment Offers and Decrement Bids*, which are bidding practices relating to Increment Offers and Decrement Bids that cause Day-Ahead LMPs not to achieve the degree of convergence with Real-Time LMPs that would be expected in a workably competitive market, more fully addressed in Section III.A.11 of this ***Appendix A***.

(iv) *Anti-competitive Demand Bids*, which are addressed in Section III.A.10 of this ***Appendix A.***

(v) Other categories of conduct that have material effects on prices or NCPC payments in the New England Markets. The Internal Market Monitor, in consultation with the External Market Monitor, shall; (i) seek to amend ***Appendix A*** as may be appropriate to include any such conduct that would substantially distort or impair the competitiveness of any of

the New England Markets; and (ii) seek such other authorization to mitigate the effects of such conduct from the Commission as may be appropriate.

(k) Perform such additional monitoring as the Internal Market Monitor deems necessary, including without limitation, monitoring for:

- (i) Anti-competitive gaming of Resources;
- (ii) Conduct and market outcomes that are inconsistent with competitive markets;
- (iii) Flaws in market design or software or in the implementation of rules by the ISO that create inefficient incentives or market outcomes;
- (iv) Actions in one market that affect price in another market;
- (v) Other aspects of market implementation that prevent competitive market results, the extent to which market rules, including this ***Appendix A***, interfere with efficient market operation, both short-run and long-run; and
- (vi) Rules or conduct that creates barriers to entry into a market.

The Internal Market Monitor will include significant results of such monitoring in its reports under Section III.A.17 of this ***Appendix A***. Monitoring under this Section III.A.2.3(k) cannot serve as a basis for mitigation under III.A.11 of this ***Appendix A.*** If the Internal Market Monitor concludes as a result of its monitoring that additional specific monitoring thresholds or mitigation remedies are necessary, it may proceed under Section III.A.20.

(l) Propose to the ISO and Market Participants appropriate mitigation measures or market rule changes for conduct that departs significantly from the conduct that would be expected under competitive market conditions but does not rise to the thresholds specified in Sections III.A.5, III.A.10, or III.A.11. In considering whether to recommend such changes, the Internal Market Monitor shall evaluate whether the conduct has a significant effect on market prices or NCPC payments as specified below. The Internal Market Monitor will not recommend changes if it determines, from information provided by Market Participants (or parties that would be subject to mitigation) or from other information available to the Internal Market Monitor, that the conduct and associated price or NCPC payments under investigation are attributable to legitimate competitive market forces or incentives.

(m) Evaluate physical withholding of Supply Offers in accordance with Section III.A.4 below for referral to the Commission in accordance with ***Appendix B*** of this Market Rule l.

(n) If and when established, participate in a committee of regional market monitors to review issues associated with interregional transactions, including any barriers to efficient trade and competition.

III.A.2.4. Overview of the Internal Market Monitor's Mitigation Functions.

III.A.2.4.1. Purpose.

The mitigation measures set forth in this ***Appendix A*** for mitigation of market power are intended to provide the means for the Internal Market Monitor to mitigate the market effects of any actions or transactions that are without a legitimate business purpose and that are intended to or foreseeably could manipulate market prices, market conditions, or market rules for electric energy or electricity products. Actions or transactions undertaken by a Market Participant that are explicitly contemplated in Market Rule l (such as virtual supply or load bidding) or taken at the direction of the ISO are not in violation of this ***Appendix A***. These mitigation measures are intended to minimize interference with open and competitive markets, and thus to permit to the maximum extent practicable, price levels to be determined by competitive forces under the prevailing market conditions. To that end, the mitigation measures authorize the mitigation of only specific conduct that exceeds well-defined thresholds specified below. When implemented, mitigation measures affecting the LMP or clearing prices in other markets will be applied *ex ante*. Nothing in this ***Appendix A***, including the application of a mitigation measure, shall be deemed to be a limitation of the ISO's authority to evaluate Market Participant behavior for potential sanctions under ***Appendix B*** of this Market Rule 1.

III.A.2.4.2. Conditions for the Imposition of Mitigation.

(a) Imposing Mitigation. To achieve the foregoing purpose and objectives, mitigation measures are imposed pursuant to Sections III.A.5, III.A.10, and III.A.11 below:

(b) Notwithstanding the foregoing or any other provision of this ***Appendix A***, and as more fully described in Section III.B.3.2.6 of ***Appendix B*** to this Market Rule 1, certain economic decisions shall not be deemed a form of withholding or otherwise inconsistent with competitive conduct.

III.A.2.4.3. Applicability.

Mitigation measures may be applied to Supply Offers, Increment Offers, Demand Bids, and Decrement Bids, as well as to the scheduling or operation of a generation unit or transmission facility.

III.A.2.4.4. Mitigation Not Provided for Under This *Appendix A*.

The Internal Market Monitor shall monitor the New England Markets for conduct that it determines constitutes an abuse of market power but does not trigger the thresholds specified below for the imposition of mitigation measures by the Internal Market Monitor. If the Internal Market Monitor identifies any such conduct, and in particular conduct exceeding the thresholds specified in this ***Appendix A***, it may make a filing under §205 of the Federal Power Act ("§205") with the Commission requesting authorization to apply appropriate mitigation measures. Any such filing shall identify the particular conduct the Internal Market Monitor believes warrants mitigation, shall propose a specific mitigation measure for the conduct, and shall set forth the Internal Market Monitor's justification for imposing that mitigation measure.

III.A.2.4.5. Duration of Mitigation.

Any mitigation measure imposed on a specific Market Participant, as specified below, shall expire not later than six months after the occurrence of the conduct giving rise to the measure, or at such earlier time as may be specified by the Internal Market Monitor or as otherwise provided in this ***Appendix A*** or in ***Appendix B*** to this Market Rule 1.

III.A.3. Consultation Prior to Determination of Reference Levels for Physical and Financial Parameters of Resources; Fuel Price Adjustments.

Upon request of a Market Participant or at the initiative of the Internal Market Monitor, the Internal Market Monitor shall consult with a Market Participant with respect to the information and analysis used to determine Reference Levels under Section III.A.7 for that Market Participant. In order for the Internal Market Monitor to revise Reference Levels or treat an offer as not violating applicable conduct tests specified in Section III.A.5.5 for an Operating Day for which the offer is submitted, all cost data and other information, other than automated index-based cost data received by the Internal Market Monitor from third party vendors, cost data and information calculated by the Internal Market Monitor, and cost data and information provided under the provisions of Section III.A.3.1 or Section III.A.3.2, must be submitted by a Market Participant, and all consultations must be completed, no later than 5:00 p.m. of the second business day prior to the Operating Day for which the Reference Level will be effective. Adjustments to fuel prices after this time must be submitted in accordance with the fuel price adjustment provisions in Section III.A.3.4.

III.A.3.1. Consultation Prior to Offer.

If an event occurs within the 24 hour period prior to the Operating Day that a Market Participant, including a Market Participant that is not permitted to submit a fuel price adjustment pursuant to Section III.A.3.4(d) believes will cause the operating cost of a Resource to exceed the level that would violate one of the conduct tests specified in Section III.A.5 of this ***Appendix A***, the Market Participant may contact the Internal Market Monitor to provide an explanation of the increased costs. In order for the information to be considered for the purposes of the Day-Ahead Energy Market, the Market Participant must contact the Internal Market Monitor at least 30 minutes prior to the close of the Day-Ahead Energy Market. In order for the information to be considered for purposes of the first commitment analysis performed following the close of the Re-Offer Period, the Market Participant must contact the Internal Market Monitor at least 30 minutes prior to the close of the Re-Offer Period. Cost information submitted thereafter shall be considered in subsequent commitment and dispatch analyses if received between 8:00 a.m. and 5:00 p.m. and at least one hour prior to the close of the next hourly Supply Offer submittal period. If the Internal Market Monitor determines that there is an increased cost, the Internal Market Monitor will either update the Reference Level or treat an offer as not violating applicable conduct tests specified in Section III.A.5.5 for the Operating Day for which the offer is submitted. Any request and all supporting cost data and other verifiable supporting information must be submitted to the Internal Market Monitor prior to the Market participant's submission of the offer.

If a Market Participant believes that the fuel price determined under Section III.A.7.5(e) should be modified, it may contact the Internal Market Monitor to request a change to the fuel price and provide an explanation of the basis for the change. Any request to change the fuel price determined under Section III.A.7.5(e) must be received between the hours of 8:00 a.m. and 5:00 p.m. on any day.

III.A.3.2. Dual Fuel Resources.

In evaluating bids or offers under this ***Appendix A*** for dual fuel Resources, the Internal Market Monitor shall utilize the fuel type specified in the Supply Offer for the calculation of Reference Levels pursuant to Section III.A.7 below. If a Market Participant specifies a fuel type in the Supply Offer that, at the time the Supply Offer is submitted, is the higher cost fuel available to the Resource, then if the ratio of the higher cost fuel to the lower cost fuel, as calculated in accordance with the formula specified below, is greater than 1.75, the Market Participant must within five Business Days:

(a) provide the Internal Market Monitor with written verification as to the cause for the use of the higher cost fuel.

(b) provide the Internal Market Monitor with evidence that the higher cost fuel was used.

If the Market Participant fails to provide supporting information demonstrating the use of the higher-cost fuel within five Business Days of the Operating Day, then the Reference Level based on the lower cost fuel will be used in place of the Supply Offer for settlement purposes.

For purposes of this Section III.A.3.2, the ratio of the Resource's higher cost fuel to the lower cost fuel is calculated as, for the two primary fuels utilized in the dispatch of the Resource, the maximum fuel index price for the Operating Day divided by the minimum fuel index price for the Operating Day, using the two fuel indices that are utilized in the calculation of the Resource's Reference Levels for the Day-Ahead Energy Market for that Operating Day.

III.A.3.3. Market Participant Access to its Reference Levels.

The Internal Market Monitor will make available to the Market Participant the Reference Levels applicable to that Market Participant's Supply Offers through the MUI. Updated Reference Levels will be made available whenever calculated. The Market Participant shall not modify such Reference Levels in the ISO's or Internal Market Monitor's systems.

III.A.3.4. Fuel Price Adjustments.

(a) A Market Participant may submit a fuel price, to be used in calculating the Reference Levels for a Resource's Supply Offer, whenever the Market Participant's expected price to procure fuel for the Resource will be greater than that used by the Internal Market Monitor in calculating the Reference Levels for the Supply Offer. A fuel price may be submitted for Supply Offers entered in the Day-Ahead Energy Market, the Re-Offer Period, or for a Real-Time Offer Change. A fuel price is subject to the following conditions:

(i) In order for the submitted fuel price to be utilized in calculating the Reference Levels for a Supply Offer, the fuel price must be submitted prior to the applicable Supply Offer deadline,

(ii) The submitted fuel price must reflect the price at which the Market Participant expects to be able to procure fuel to supply energy under the terms of its Supply Offer, exclusive of resource-specific transportation costs. Modifications to Reference Levels based on changes to transportation costs must be addressed through the consultation process specified in Section III.A.3.1.

(iii) The submitted fuel price may be no lower than the lesser of (1) 110% of the fuel price used by the Internal Market Monitor in calculating the Reference Levels for the Resource's Supply Offer

or (2) the fuel price used by the Internal Market Monitor in calculating the Reference Levels for the Resource's Supply Offer plus $2.50/MMbtu.

(b) Within five Business Days following submittal of a fuel price, a Market Participant must provide the Internal Market Monitor with documentation or analysis to support the submitted fuel price, which may include but is not limited to (i) an invoice or purchase confirmation for the fuel utilized or (ii) a quote from a named supplier or (iii) a price from a publicly available trading platform or price reporting agency, demonstrating that the submitted fuel price reflects the cost at which the Market Participant expected to purchase fuel for the operating period covered by the Supply Offer, as of the time that the Supply Offer was submitted, under an arm's length fuel purchase transaction. Any amount to be added to the quote from a named supplier, or to a price from a publicly available trading platform or price reporting agency, must be submitted and approved using the provision for consultations prior to the determination of Reference Levels in Section III.A.3. The submitted fuel price must be consistent with the fuel price reflected on the submitted invoice or purchase confirmation for the fuel utilized, the quote from a named supplier or the price from a publicly available trading platform or price reporting agency, plus any approved adder, or the other documentation or analysis provided to support the submitted fuel price.

(c) If, within a 12 month period, the requirements in sub-section (b) are not met for a Resource and, for the time period for which the fuel price adjustment that does not meet the requirements in sub-section (b) was submitted, (i) the Market Participant was determined to be pivotal according to the pivotal supplier test described in Section III.A.5.2.1or (ii) the Resource was determined to be in a constrained area according to the constrained area test described in Section III.A.5.2.2 or (iii) the Resource satisfied any of the conditions described in Section III.A.5.5.6.1, then a fuel price adjustment pursuant to Section III.A.3.4 shall not be permitted for that Resource for up to six months. The following table specifies the number of months for which a Market Participant will be precluded from using the fuel price adjustment, based on the number of times the requirements in sub-section (b) are not met within the 12 month period. The 12 month period excludes any previous days for which the Market Participant was precluded from using the fuel price adjustment. The period of time for which a Market Participant is precluded from using the fuel price adjustment begins two weeks after the most-recent incident occurs.

Number of Incidents	Months Precluded (starting from most-recent incident)
1	2

2 or more	6

III.A.4. Physical Withholding.

III.A.4.1. Identification of Conduct Inconsistent with Competition.

This section defines thresholds used to identify possible instances of physical withholding. This section does not limit the Internal Market Monitor's ability to refer potential instances of physical withholding to the Commission.

Generally, physical withholding involves not offering to sell or schedule the output of or services provided by a Resource capable of serving the New England Markets when it is economic to do so. Physical withholding may include, but is not limited to:

(a) falsely declaring that a Resource has been forced out of service or otherwise become unavailable,

(b) refusing to make a Supply Offer, or schedules for a Resource when it would be in the economic interest absent market power, of the withholding entity to do so,

(c) operating a Resource in Real-Time to produce an output level that is less than the ISO Dispatch Rate, or

(d) operating a transmission facility in a manner that is not economic, is not justified on the basis of legitimate safety or reliability concerns, and contributes to a binding transmission constraint.

III.A.4.2. Thresholds for Identifying Physical Withholding.

III.A.4.2.1. Initial Thresholds.

Except as specified in subsection III.A.4.2.4 below, the following initial thresholds will be employed by the Internal Market Monitor to identify physical withholding of a Resource:

(a) Withholding that exceeds the lower of 10% or 100 MW of a Resource's capacity;

(b) Withholding that exceeds in the aggregate the lower of 5% or 200 MW of a Market Participant's total capacity for Market Participants with more than one Resource; or

(c) Operating a Resource in Real-Time at an output level that is less than 90% of the ISO's Dispatch Rate for the Resource.

III.A.4.2.2. Adjustment to Generating Capacity.

The amounts of generating capacity considered withheld for purposes of applying the foregoing thresholds shall include unjustified deratings, that is, falsely declaring a Resource derated, and the portions of a Resource's available output that are not offered. The amounts deemed withheld shall not include generating output that is subject to a forced outage or capacity that is out of service for maintenance in accordance with an ISO maintenance schedule, subject to verification by the Internal Market Monitor as may be appropriate that an outage was forced.

III.A.4.2.3. Withholding of Transmission.

A transmission facility shall be deemed physically withheld if it is not operated in accordance with ISO instructions and such failure to conform to ISO instructions causes transmission congestion. A transmission facility shall not be deemed withheld if it is subject to a forced outage or is out of service for maintenance in accordance with an ISO maintenance schedule, subject to verification by the Internal Market Monitor as may be appropriate that an outage was forced.

III.A.4.2.4. Resources in Congestion Areas.

Minimum quantity thresholds shall not be applicable to the identification of physical withholding by a Resource in an area the ISO has determined is congested.

III.A.4.3. Hourly Market Impacts.

Before evaluating possible instances of physical withholding for imposition of sanctions, the Internal Market Monitor shall investigate the reasons for the change in accordance with Section III.A.3. If the physical withholding in question is not explained to the satisfaction of the Internal Market Monitor, the Internal Market Monitor will determine whether the conduct in question causes a price impact in the New England Markets in excess of any of the thresholds specified in Section III.A.5, as appropriate.

III.A.5. Mitigation.

III.A.5.1. Resources with Capacity Supply Obligations.

Only Supply Offers associated with Resources with Capacity Supply Obligations will be evaluated for economic withholding in the Day-Ahead Energy Market. All Supply Offers will be evaluated for economic withholding in the Real-Time Energy Market.

III.A.5.1.1. Resources with Partial Capacity Supply Obligations.

Supply Offers associated with Resources with a Capacity Supply Obligation for less than their full capacity shall be evaluated for economic withholding and mitigation as follows:

(a) all Supply Offer parameters shall be reviewed for economic withholding;

(b) the energy price Supply Offer parameter shall be reviewed for economic withholding up to and including the higher of: (i) the block containing the Resource's Economic Minimum Limit, or; (ii) the highest block that includes any portion of the Capacity Supply Obligation;

(c) if a Resource with a partial Capacity Supply Obligation consists of multiple assets, the offer blocks associated with the Resource that shall be evaluated for mitigation shall be determined by using each asset's Seasonal Claimed Capability value in proportion to the total of the Seasonal Claimed Capabilities for all of the assets that make up the Resource. The Lead Market Participant of a Resource with a partial Capacity Supply Obligation consisting of multiple assets may also propose to the Internal Market Monitor the offer blocks that shall be evaluated for mitigation based on an alternative allocation on a monthly basis. The proposal must be made at least five Business Days prior to the start of the month. A proposal shall be rejected by the Internal Market Monitor if the designation would be inconsistent with competitive behavior

III.A.5.2. Structural Tests.

There are two structural tests that determine which mitigation thresholds are applied to a Supply Offer:

(a) if a supplier is determined to be pivotal according to the pivotal supplier test, then the thresholds in Section III.A.5.5.1 "General Threshold Energy Mitigation" and Section III.A.5.5.4 "General Threshold Commitment Mitigation" apply, and;

(b) if a Resource is determined to be in a constrained area according to the constrained area test, then the thresholds in Section III.A.5.5.2 "Constrained Area Energy Mitigation" and Section III.A.5.5.4 "Constrained Area Commitment Mitigation" apply.

III.A.5.2.1. Pivotal Supplier Test.

The pivotal supplier test examines whether a Market Participant has aggregate energy Supply Offers (up to and including Economic Max) that exceed the supply margin in the Real-Time Energy Market. A Market Participant whose aggregate energy associated with Supply Offers exceeds the supply margin is a pivotal supplier.

The supply margin for an interval is the total energy Supply Offers from available Resources (up to and including Economic Max), less total system load (as adjusted for net interchange with other Control Areas, including Operating Reserve). Resources are considered available for an interval if they can provide energy within the interval. The applicable interval for the current operating plan in the Real-Time Energy Market is any of the hours in the plan. The applicable interval for UDS is the interval for which UDS issues instructions.

The pivotal supplier test shall be run prior to each determination of a new operating plan for the Operating Day, and prior to each execution of the UDS.

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III.A.5.2.2. Constrained Area Test.

A Resource is considered to be within a constrained area if:

(a) for purposes of the Real-Time Energy Market, the Resource is located on the import-constrained side of a binding constraint and there is a sensitivity to the binding constraint such that the UDS used to relieve transmission constraints would commit or dispatch the Resource in order to relieve that binding transmission constraint, or;

(b) for purposes of the Day-Ahead Energy Market, the LMP at the Resource's Node exceeds the LMP at the Hub by more than $25/MWh.

III.A.5.3. Calculation of Impact Test in the Day-Ahead Energy Market.

The price impact for the purposes of Section III.A.5.5.2 "Constrained Area Energy Mitigation" is equal to the difference between the LMP at the Resource's Node and the LMP at the Hub.

III.A.5.4. Calculation of Impact Tests in the Real-Time Energy Market.

The energy price impact test applied in the Real-Time Energy Market shall compare two LMPs at the Resource's Node. The first LMP will be calculated based on the Supply Offers submitted for all Resources. If a Supply Offer has been mitigated in a prior interval, the calculation of the first LMP shall be based on the mitigated value. The second LMP shall be calculated substituting Reference Levels for

Supply Offers that have failed the applicable conduct test. The difference between the two LMPs is the price impact of the conduct violation.

A Supply Offer shall be determined to have no price impact if the offer block that violates the conduct test is:

(a) less than the LMP calculated using the submitted Supply Offers, and less than the LMP calculated using Reference Levels for Supply Offers that have failed the conduct test, or;

(b) greater than the LMP calculated using the submitted Supply Offers, and greater than the LMP calculated using Reference Levels for Supply Offers that have failed the conduct test, and the Resource has not been dispatched into the offer block that exceeds the LMP.

III.A.5.5. Mitigation by Type.

III.A.5.5.1. General Threshold Energy Mitigation.

III.A.5.5.1.1. Applicability.

Mitigation pursuant to this section shall be applied to all Supply Offers in the Real-Time Energy Market submitted by a Lead Market Participant that is determined to be a pivotal supplier in the Real-Time Energy Market.

III.A.5.5.1.2. Conduct Test.

A Supply Offer fails the conduct test for general threshold energy mitigation if any offer block price exceeds the Reference Level by an amount greater than 300% or $100/MWh, whichever is lower. Offer block prices below $25/MWh are not subject to the conduct test.

III.A.5.5.1.3. Impact Test.

A Supply Offer that fails the conduct test for general threshold energy mitigation shall be evaluated against the impact test for general threshold energy mitigation. A Supply Offer fails the impact test for general threshold energy mitigation if there is an increase in the LMP greater than 200% or $100/MWh, whichever is lower as determined by the real-time impact test.

III.A.5.5.1.4. Consequence of Failing Both Conduct and Impact Test.

If a Supply Offer fails the general threshold conduct and impact tests, then the financial parameters of the Supply Offer shall be set to their Reference Levels, including all energy offer block prices and all types of Start-Up Fees and the No-Load Fee.

III.A.5.5.2. Constrained Area Energy Mitigation.

III.A.5.5.2.1. Applicability.

Mitigation pursuant to this section shall be applied to Supply Offers in the Day-Ahead Energy Market and Real-Time Energy Market associated with a Resource determined to be within a constrained area.

III.A.5.5.2.2. Conduct Test.

A Supply Offer fails the conduct test for constrained area energy mitigation if any offer block price exceeds the Reference Level by an amount greater than 50% or $25/MWh, whichever is lower.

III.A.5.5.2.3. Impact Test.

A Supply Offer fails the impact test for constrained area energy mitigation if there is an increase greater than 50% or $25/MWh, whichever is lower, in the LMP as determined by the day-ahead or real-time impact test.

III.A.5.5.2.4. Consequence of Failing Both Conduct and Impact Test.

If a Supply Offer fails the constrained area conduct and impact tests, then the financial parameters of the Supply Offer shall be set to their Reference Levels, including all energy offer blocks and all types of Start-Up Fees and the No-Load Fee.

III.A.5.5.3. Manual Dispatch Energy Mitigation.

III.A.5.5.3.1. Applicability.

Mitigation pursuant to this section shall be applied to Supply Offers associated with a Resource, when the Resource is manually dispatched above the Economic Minimum Limit value specified in the Resource's Supply Offer and the energy price parameter of its Supply Offer at the Desired Dispatch Point is greater than the Real-Time Price at the Resource's Node.

III.A.5.5.3.2. Conduct Test.

A Supply Offer fails the conduct test for manual dispatch energy mitigation if any offer block price divided by the Reference Level is greater than 1.10.

III.A.5.5.3.3. Consequence of Failing the Conduct Test.

If a Supply Offer for a Resource fails the manual dispatch energy conduct test, then the financial parameters of the Supply Offer shall be set to their Reference Levels, including all energy offer blocks and all types of Start-Up Fees and the No-Load Fee.

III.A.5.5.4. General Threshold Commitment Mitigation.

III.A.5.5.4.1. Applicability.

Mitigation pursuant to this section shall be applied to all Supply Offers in the Real-Time Energy Market submitted by a Lead Market Participant that is determined to be a pivotal supplier in the Real-Time Energy Market.

III.A.5.5.4.2. Conduct Test.

A Resource shall fail the conduct test for general threshold commitment mitigation if the low Load Cost at Offer divided by the Low Load Cost at Reference Level is greater than 3.00.

III.A.5.5.4.3. Consequence of Failing Conduct Test.

If a Resource fails the general threshold commitment conduct test, then all financial parameters of its Supply Offer are set to their Reference Levels.

III.A.5.5.5. Constrained Area Commitment Mitigation.

III.A.5.5.5.1. Applicability.

Mitigation pursuant to this section shall be applied to any Resource determined to be within a constrained area in the Real-Time Energy Market.

III.A.5.5.5.2. Conduct Test.

A Resource shall fail the conduct test for constrained area commitment mitigation if the Low Load Cost at Offer divided by the Low Load Cost at Reference Level is greater than 1.25.

III.A.5.5.5.3. Consequence of Failing Test.

If a Supply Offer fails the constrained area commitment conduct test, then all financial parameters of its Supply Offer are set to their Reference Levels.

III.A.5.5.6. Reliability Commitment Mitigation.

III.A.5.5.6.1. Applicability.

Mitigation pursuant to this section shall be applied to Supply Offers for Resources that are (a) committed to provide, or Resources that are required to remain online to provide, one or more of the following:

i. local first contingency;
ii. local second contingency;
iii. VAR or voltage;
iv. distribution (Special Constraint Resource Service);
v. dual fuel resource auditing;

(b) otherwise manually committed by the ISO for reasons other than meeting anticipated load plus reserve requirements.

III.A.5.5.6.2. Conduct Test.

A Supply Offer shall fail the conduct test for local reliability commitment mitigation if the Low Load Cost at Offer divided by the Low Load Cost at Reference Level is greater than 1.10.

III.A.5.5.6.3. Consequence of Failing Test.

If a Supply Offer fails the local reliability commitment conduct test, it shall be evaluated for commitment based on an offer with all financial parameters set to their Reference Levels. This includes all offer blocks and all types of Start-Up Fees and the No-Load Fee. If a Resource is committed, then all financial parameters of its Supply Offer are set to their Reference Level.

III.A.5.5.7. Start-Up Fee and No-Load Fee Mitigation.

III.A.5.5.7.1. Applicability.

Mitigation pursuant to this section shall be applied to any Supply Offer submitted in the Day-Ahead Energy Market or Real-Time Energy Market if the resource is committed.

III.A.5.5.7.2. Conduct Test.

A Supply Offer shall fail the conduct test for Start-Up Fee and No-Load Fee mitigation if its Start-Up Fee or No-Load Fee divided by the Reference Level for that fee is greater than 3.

III.A.5.5.7.3. Consequence of Failing Conduct Test.

If a Supply Offer fails the conduct test, then all financial parameters of its Supply Offer shall be set to their Reference Levels.

III.A.5.5.8. Low Load Cost.

Low Load Cost, which is the cost of operating the Resource at its Economic Minimum Limit, is calculated as the sum of:

(a) If the Resource is starting from an offline state, the Start-Up Fee;

(b) The sum of the No Load Fees for the Commitment Period; and

(c) The sum of the hourly values resulting from the multiplication of the price of energy at the Resource's Economic Minimum Limit times its Economic Minimum Limit, for each hour of the Commitment Period.

All Supply Offer parameter values used in calculating the Low Load Cost are the values in place at the time the commitment decision is made.

Low Load Cost at Offer equals the Low Load Cost calculated with financial parameters of the Supply Offer as submitted by the Lead Market Participant.

Low Load Cost at Reference Level equals the Low Load Cost calculated with the financial parameters of the Supply Offer set to Reference Levels.

For Low Load Cost at Offer, the price of energy is the energy price parameter of the Resource's Supply Offer at the Economic Minimum Limit offer block. For Low Load Cost at Reference Level, the price of energy is the energy price parameter of the Resource's Reference Level at the Economic Minimum Limit offer block.

III.A.5.6. Duration of Energy Threshold Mitigation.

Any mitigation imposed pursuant to Sections III.A.5.5.1 “General Threshold Energy Mitigation” or III.A.5.5.2 “Constrained Area Energy Mitigation” is in effect for the following duration:

(a) in the Real-Time Energy Market, mitigation starts when the impact test violation occurs and remains in effect until there is one complete hour in which:

   i. for general threshold mitigation, the Market Participant whose Supply Offer is subject to mitigation is not a pivotal supplier; or,

   ii. for constrained area energy mitigation, the Resource is not located within a constrained area.

(b) in the Day-Ahead Energy Market (applicable only for Section III.A.5.5.2 “Constrained Area Energy Mitigation”), mitigation is in effect in each hour in which the impact test is violated.

Any mitigation imposed pursuant to Section III.A.5.5.3 “Manual Dispatch Energy Mitigation” is in effect for at least one hour until the earlier of either (a) the hour when manual dispatch is no longer in effect and the Resource returns to its Economic Minimum Limit, or (b) the hour when the energy price parameter of its Supply Offer at the Desired Dispatch Point is no longer greater than the Real-Time Price at the Resource’s Node.

III.A.5.7. Duration of Commitment Mitigation.

Any mitigation imposed pursuant to Sections III.A.5.5.4 “General Threshold Commitment Mitigation”, III.A.5.5.5 “Constrained Area Commitment Mitigation”, or III.A.5.5.6 “Reliability Commitment Mitigation” is in effect for the duration of the Commitment Period.

III.A.5.8. Duration of Start-Up Fee and No-Load Fee Mitigation.

Any mitigation imposed pursuant to Sections III.A.5.5.7 “Start-Up Fee and No-Load Fee Mitigation” is in effect for any hour in which the Supply Offer fails the conduct test in Section III.A.5.5.7.2.

III.A.5.9. Correction of Mitigation.

If the Internal Market Monitor determines that there are one or more errors in the mitigation applied in an Operating Day due to data entry, system or software errors by the ISO or the Internal Market Monitor, the Internal Market Monitor shall notify the market monitoring contacts specified by the Lead Market Participant within five Business Days of the applicable Operating Day. The ISO shall correct the error as

part of the Data Reconciliation Process by applying the correct values to the relevant Supply Offer in the settlement process.

The permissibility of correction of errors in mitigation, and the timeframes and procedures for permitted corrections, are addressed solely in this section and not in those sections of Market Rule 1 relating to settlement and billing processes.

III.A.5.10. Delay of Day-Ahead Energy Market Due to Mitigation Process.

The posting of the Day-Ahead Energy Market results may be delayed if necessary for the completion of mitigation procedures.

III.A.6. Physical and Financial Parameter Offer Thresholds.

Physical parameters of a Supply Offer are limited to thresholds specified in this section. Physical parameters are limited by the software accepting offers, except those that can be re-declared in real time during the Operating Day. Parameters that exceed the thresholds specified here but are not limited through the software accepting offers are subject to Internal Market Monitor review after the Operating Day and possible referral to the Commission under Section III.A.19 of this Appendix.

III.A.6.1. Time-Based Offer Parameters.

Supply Offer parameters that are expressed in time (i.e., Minimum Run Time, Minimum Down Time, Start-Up Time, and Notification Time) shall have a threshold of two hours for an individual parameter or six hours for the combination of the time-based offer parameters compared to the Resource's Reference Levels. Offers may not exceed these thresholds in a manner that reduce the flexibility of the Resource. To determine if the six hour threshold is exceeded, all time-based offer parameters will be summed for each start-up state (hot, intermediate and cold). If the sum of the time-based offer parameters for a start-up state exceeds six hours above the sum of the Reference Levels for those offer parameters, then the six hour threshold is exceeded.

III.A.6.2. Financial Offer Parameters.

The Start-Up Fee and the No-Load Fee values of a Resource's Supply Offer may be no greater than three times the Start-Up Fee and No-Load Fee Reference Level values for the Resource. In the event a fuel price has been submitted under Section III.A.3.4, the Start-Up Fee and No-Load Fee for the associated Supply Offer shall be limited in a Real-Time Offer Change. The limit shall be the percent increase in the new fuel price, relative to the fuel price otherwise used by the Internal Market Monitor, multiplied by the

Start-Up Fee or No-Load Fee from the Re-Offer Period. Absent a fuel price adjustment, a Start-Up Fee or No-Load Fee may be changed in a Real-Time Offer Change to no more than the Start-Up Fee and No-Load Fee values submitted for the Re-Offer Period.

III.A.6.3. Other Offer Parameters.

Non-financial or non-time-based offer parameters shall have a threshold of a 100% increase, or greater, for parameters that are minimum values, or a 50% decrease, or greater, for parameters that are maximum values (including, but not limited to, ramp rates, Economic Maximum Limits and maximum starts per day) compared to the Resource's Reference Levels.

Offer parameters that are limited by performance caps or audit values imposed by the ISO are not subject to the provisions of this section.

III.A.7. Calculation of Resource Reference Levels for Physical Parameters and Financial Parameters of Resources.

Market Participants are responsible for providing the Internal Market Monitor with all the information and data necessary for the Internal Market Monitor to calculate up-to-date Reference Levels for each of a Market Participant's Resources.

III.A.7.1. Methods for Determining Reference Levels for Physical Parameters.

The Internal Market Monitor will calculate a Reference Level for each element of a bid or offer that is expressed in units other than dollars (such as time-based or quantity level bid or offer parameters) on the basis of one or more of the following:

(a) Original equipment manufacturer (OEM) operating recommendations and performance data for all Resource types in the New England Control Area, grouped by unit classes, physical parameters and fuel types.

(b) Applicable environmental operating permit information currently on file with the issuing environmental regulatory body.

(c) Verifiable Resource physical operating characteristic data, including but not limited to facility and/or Resource operating guides and procedures, historical operating data and any verifiable documentation related to the Resource, which will be reviewed in consultation with the Market Participant.

III.A.7.2. Methods for Determining Reference Levels for Financial Parameters of Offers.

The Reference Levels for Start-Up Fees, No-Load Fees, Interruption Costs and offer blocks will be calculated separately and assuming no costs from one component are included in another component.

III.A.7.2.1. Order of Reference Level Calculation.

The Internal Market Monitor will calculate a Reference Level for each offer block of an offer according to the following hierarchy, under which the first method that can be calculated is used:

(a) accepted offer-based Reference Levels pursuant to Section III.A.7.3;
(b) LMP-based Reference Levels pursuant to Section III.A.7.4; and,
(c) cost-based Reference Levels pursuant to Section III.A.7.5.

III.A.7.2.2. Circumstances in Which Cost-Based Reference Levels Supersede the Hierarchy of Reference Level Calculation.

In the following circumstances, cost-based Reference Levels shall be used notwithstanding the hierarchy specified in Section III.A.7.2.1.

(a) When in any hour the cost-based Reference Level is higher than either the accepted offer-based or LMP-based Reference Level.
(b) When the Supply Offer parameter is a Start-Up Fee or the No-Load Fee.
(c) For any Operating Day for which the Lead Market Participant requests the cost-based Reference Level.
(d) For any Operating Day for which, during the previous 90 days:
    (i) the Resource has been flagged for VAR, SCR, or as a Local Second Contingency Protection Resource for any hour in the Day-Ahead Energy Market or the Real-Time Energy Market, and;
    (ii) the ratio of the sum of the operating hours for days for which the Resource has been flagged during the previous 90 days in which the number of hours operated out of economic merit order in the Day-Ahead Energy Market and the Real-Time Energy Market exceed the number of hours operated in economic merit order in the Day-Ahead Energy Market and Real-Time Energy Market, to the total number of operating hours in the Day-Ahead Energy Market and Real-Time Energy Market during the previous 90 days is greater than or equal to 50 percent.
(e) When in any hour the incremental energy parameter of an offer, including adjusted offers pursuant to Section III.2.4, is greater than $1,000/MWh.

For the purposes of this subsection:

i. A flagged day is any day in which the Resource has been flagged for VAR, SCR, or as a Local Second Contingency Protection Resource for any hour in either the Day-Ahead Energy Market or the Real-Time Energy Market.

ii. Operating hours are the hours in the Day-Ahead Energy Market for which a Resource has cleared output (MW) greater than zero and hours in the Real-Time Energy Market for which a Resource has metered output (MW) greater than zero. For days for which Real-time Energy Market metered values are not yet available in the ISO's or the Internal Market Monitor's systems, telemetered values will be used.

iii. Self-scheduled hours will be excluded from all of the calculations described in this subsection, including the determination of operating hours.

iv. The determination as to whether a Resource operated in economic merit order during an hour will be based on the energy offer block within which the Resource is operating.

(e) The Market Participant submits a fuel price pursuant to Section III.A.3.4. When the Market Participant submits a fuel price for any hour of a Supply Offer in the Day-Ahead Energy Market or Re-Offer Period, then the cost-based Reference Level is used for the entire Operating Day. If a fuel price is submitted for a Supply Offer after the close of the Re-Offer Period for the next Operating Day or for the current Operating Day, then the cost-based Reference Level for the Supply Offer is used from the time of the submittal to the end of the Operating Day.

(f) When the Market Participant submits a change to any of the following parameters of the Supply Offer after the close of the Re-Offer Period:

(i) hot, intermediate, or cold Start-Up Fee, or a corresponding fuel blend,

(ii) No-Load Fee or its corresponding fuel blends,

(iii) whether to include the Start-Up Fee and No-Load Fee in the Supply Offer,

(iv) the quantity or price value of any Block in the Supply Offer or its corresponding fuel blends, and

(v) whether to use the offer slope for the Supply Offer,

then, the cost-based Reference Level for the Supply Offer will be used from the time of the submittal to the end of the Operating Day.

III.A.7.3. Accepted Offer-Based Reference Level.

The Internal Market Monitor shall calculate the accepted offer-based Reference Level as the lower of the mean or the median of a generating Resource's Supply Offers that have been accepted and are part of the seller's Day-Ahead Generation Obligation or Real-Time Generation Obligation in competitive periods over the previous 90 days, adjusted for changes in fuel prices utilizing fuel indices generally applicable for the location and type of Resource. For purposes of this section, a competitive period is an Operating Day in which the Resource is scheduled in economic merit order.

III.A.7.4. LMP-Based Reference Level.

The Internal Market Monitor shall calculate the LMP-based Reference Level as the mean of the LMP at the Resource's Node during the lowest-priced 25% of the hours that the Resource was dispatched over the previous 90 days for similar hours (on-peak or off-peak), adjusted for changes in fuel prices.

III.A.7.5. Cost-Based Reference Level.

The Internal Market Monitor shall calculate cost-based Reference Levels taking into account information on costs provided by the Market Participant though the consultation process prescribed in Section III.A.3.

The following criteria shall be applied to estimates of cost:

(a) The provision of cost estimates by a Market Participant shall conform with the timing and requirements of Section III.A.3 "Consultation Prior to Determination of Reference Levels for Physical and Financial Parameters of Resources".

(b) Costs must be documented.

(c) All cost estimates shall be based on estimates of current market prices or replacement costs and not inventory costs wherever possible. All cost estimates, including opportunity cost estimates, must be quantified and analytically supported.

(d) When market prices or replacement costs are unavailable, cost estimates shall identify whether the reported costs are the result of a product or service provided by an Affiliate of the Market Participant.

(e) The Internal Market Monitor will evaluate cost information provided by the Market Participant in comparison to other information available to the Internal Market Monitor. Reference Levels associated with Resources for which a fuel price has been submitted under Section III.A.3.4 shall be calculated using the lower of the submitted fuel price or a price, calculated by the Internal Market Monitor, that takes account of the following factors and conditions:

i. Fuel market conditions, including the current spread between bids and asks for current fuel delivery, fuel trading volumes, near-term price quotes for fuel, expected natural gas heating demand, and Market Participant-reported quotes for trading and fuel costs; and
ii. Fuel delivery conditions, including current and forecasted fuel delivery constraints and current line pack levels for natural gas pipelines.

III.A.7.5.1. Estimation of Incremental Operating Cost.

The Internal Market Monitor's determination of a Resource's marginal costs shall include an assessment of the Resource's incremental operating costs in accordance with the following formulas,

Incremental Energy/Reduction:
(incremental heat rate * fuel costs) + (emissions rate * emissions allowance price) + variable operating and maintenance costs + opportunity costs.

Opportunity costs may include, but are not limited to, economic costs associated with complying with:

(a) emissions limits;
(b) water storage limits;
(c) other operating permits that limit production of energy; and
(d) reducing electricity consumption.

No-Load:
(no-load fuel use * fuel costs) + (no-load emissions * emission allowance price)
+ no-load variable operating and maintenance costs + other no-load costs that are not fuel, emissions or variable and maintenance costs.

Start-Up/Interruption:
(start-up fuel use * fuel costs) + (start-up emissions * emission allowance price) + start-up variable and maintenance costs + other start-up costs that are not fuel, emissions or variable and maintenance costs.

III.A.8. [Reserved.]

III.A.9. Regulation.

The Internal Market Monitor will monitor the Regulation market for conduct that it determines constitutes an abuse of market power. If the Internal Market Monitor identifies any such conduct, it may make a filing under Section 205 of the Federal Power Act with the Commission requesting authorization to apply appropriate mitigation measures or to revise Market Rule 1 to address such conduct (or both). The Internal Market Monitor may make such a filing at any time it deems necessary, and may request expedited treatment from the Commission. Any such filing shall identify the particular conduct the Internal Market Monitor believes warrants mitigation or revisions to Market Rule 1 (or both), shall propose a specific mitigation measure for the conduct or revision to Market Rule 1 (or both), and shall set forth the Internal Market Monitor's justification for imposing that mitigation measure or revision to Market Rule 1 (or both).

III.A.10. Demand Bids.

The Internal Market Monitor will monitor the Energy Market as outlined below:

(a) LMPs in the Day-Ahead Energy Market and Real-Time Energy Market shall be monitored to determine whether there is a persistent hourly deviation in any location that would not be expected in a workably competitive market.

(b) The Internal Market Monitor shall compute the average hourly deviation between Day-Ahead Energy Market and Real-Time Energy Market LMPs, measured as: $(LMP_{\text{real time}} / LMP_{\text{day ahead}}) - 1$. The average hourly deviation shall be computed over a rolling four-week period or such other period determined by the Internal Market Monitor.

(c) The Internal Market Monitor shall estimate and monitor the average percentage of each Market Participant's bid to serve load scheduled in the Day-Ahead Energy Market, using a methodology intended to identify a sustained pattern of under-bidding as accurately as deemed practicable. The average percentage will be computed over a specified time period determined by the Internal Market Monitor.

If the Internal Market Monitor determines that: (i) The average hourly deviation is greater than ten percent (10%) or less than negative ten percent (-10%), (ii) one or more Market Participants on behalf of one or more LSEs have been purchasing a substantial portion of their loads with purchases in the Real-Time Energy Market, (iii) this practice has contributed to an unwarranted divergence of LMPs between

the two markets, and (iv) this practice has created operational problems, the Internal Market Monitor may make a filing under Section 205 of the Federal Power Act with the Commission requesting authorization to apply appropriate mitigation measures or to revise Market Rule 1 to address such conduct (or both). The thresholds identified above shall not limit the Internal Market Monitor's authority to make such a filing. The Internal Market Monitor may make such a filing at any time it deems necessary, and may request expedited treatment from the Commission. Any such filing shall identify the particular conduct that the Internal Market Monitor believes warrants mitigation or revisions to Market Rule 1 (or both), shall propose a specific mitigation measure for the conduct or revision to Market Rule 1 (or both), and shall set forth the Internal Market Monitor's justification for imposing that mitigation measure or revision to Market Rule 1 (or both).

III.A.11. Mitigation of Increment Offers and Decrement Bids.

III.A.11.1. Purpose.

The provisions of this section specify the market monitoring and mitigation measures applicable to Increment Offers and Decrement Bids. An Increment Offer is one to supply energy and a Decrement Bid is one to purchase energy, in either such case not being backed by physical load or generation and submitted in the Day-Ahead Energy Market in accordance with the procedures and requirements specified in Market Rule 1 and the ISO New England Manuals.

III.A.11.2. Implementation.

III.A.11.2.1. Monitoring of Increment Offers and Decrement Bids.

Day-Ahead LMPs and Real-Time LMPs in each Load Zone or Node, as applicable, shall be monitored to determine whether there is a persistent hourly deviation in the LMPs that would not be expected in a workably competitive market. The Internal Market Monitor shall compute the average hourly deviation between Day-Ahead LMPs and Real-Time LMPs, measured as:

$(LMP_{\text{real time}} / LMP_{\text{day ahead}}) - 1$.

The average hourly deviation shall be computed over a rolling four-week period or such other period determined by the Internal Market Monitor to be appropriate to achieve the purpose of this mitigation measure.

III.A.11.3. Mitigation Measures.

If the Internal Market Monitor determines that (i) the average hourly deviation computed over a rolling four week period is greater than ten percent (10%) or less than negative ten percent (-10%), and (ii) the bid and offer practices of one or more Market Participants has contributed to a divergence between LMPs in the Day-Ahead Energy Market and Real-Time Energy Market, then the following mitigation measure may be imposed:

The Internal Market Monitor may limit the hourly quantities of Increment Offers for supply or Decrement Bids for load that may be offered in a Location by a Market Participant, subject to the following provisions:

(i) The Internal Market Monitor shall, when practicable, request explanations of the relevant bid and offer practices from any Market Participant submitting such bids.

(ii) Prior to imposing a mitigation measure, the Internal Market Monitor shall notify the affected Market Participant of the limitation.

(iii) The Internal Market Monitor, with the assistance of the ISO, will restrict the Market Participant for a period of six months from submitting any virtual transactions at the same Node(s), and/or electrically similar Nodes to, the Nodes where it had submitted the virtual transactions that contributed to the unwarranted divergence between the LMPs in the Day-Ahead Energy Market and Real-Time Energy Market.

III.A.11.4. Monitoring and Analysis of Market Design and Rules.

The Internal Market Monitor shall monitor and assess the impact of Increment Offers and Decrement Bids on the competitive structure and performance, and the economic efficiency of the New England Markets. Such monitoring and assessment shall include the effects, if any, on such bids and offers of any mitigation measures specified in this Market Rule 1.

III.A.12. Cap on FTR Revenues.

If a holder of an FTR between specified delivery and receipt Locations (i) had an Increment Offer and/or Decrement Bid that was accepted by the ISO for an applicable hour in the Day-Ahead Energy Market for delivery or receipt at or near delivery or receipt Locations of the FTR; and (ii) the result of the acceptance of such Increment Offer or Decrement Bid is that the difference in LMP in the Day-Ahead Energy Market between such delivery and receipt Locations is greater than the difference in LMP between such delivery and receipt Locations in the Real-Time Energy Market, then the Market Participant shall not receive any Transmission Congestion Credit associated with such FTR in such hour, in excess of one divided by the

number of hours in the applicable month multiplied by the amount originally paid for the FTR in the FTR Auction. A Location shall be considered at or near the FTR delivery or receipt Location if seventy-five % or more of the energy injected or withdrawn at that Location and which is withdrawn or injected at another Location is reflected in the constrained path between the subject FTR delivery and receipt Locations that were acquired in the FTR Auction.

III.A.13. Additional Internal Market Monitor Functions Specified in Tariff.

III.A.13.1. Review of Offers and Bids in the Forward Capacity Market.

In accordance with the following provisions of Section III.13 of Market Rule 1, the Internal Market Monitor is responsible for reviewing certain bids and offers made in the Forward Capacity Market. Section III.13 of Market Rule 1 specifies the nature and detail of the Internal Market Monitor's review and the consequences that will result from the Internal Market Monitor's determination following such review.

(a) [Reserved].

(b) Section III.13.1.2.3.1.6.3 - Internal Market Monitor review of Static De-List Bids, Permanent De-List Bids, and Retirement De-List Bids from an Existing Generating Capacity Resource that is associated with a Station having Common Costs.

(c) Section III.13.1.2.3.2 - Review by Internal Market Monitor of Bids from Existing Generating Capacity Resources.

(d) Section III.13.1.3.3A(d) - Review by Internal Market Monitor of offers from Existing Import Capacity Resources.

(e) Section III.13.1.3.5.6 - Review by Internal Market Monitor of Offers from New Import Capacity Resources.

(f) Section III.13.1.7 - Internal Market Monitor review of summer and winter Seasonal Claimed Capability values.

III.A.13.2. Supply Offers and Demand Bids Submitted for Reconfiguration Auctions in the Forward Capacity Market.

Section III.13.4 of Market Rule 1 addresses reconfiguration auctions in the Forward Capacity Market. As addressed in Section III.13.4.2 of Market Rule 1, a supply offer or demand bid submitted for a reconfiguration auction shall not be subject to mitigation by the Internal Market Monitor.

III.A.13.3. Monitoring of Transmission Facility Outage Scheduling.

Appendix G of Market Rule 1 addresses the scheduling of outages for transmission facilities. The Internal Market Monitor shall monitor the outage scheduling activities of the Transmission Owners. The Internal Market Monitor shall have the right to request that each Transmission Owner provide information to the Internal Market Monitor concerning the Transmission Owner's scheduling of transmission facility outages, including the repositioning or cancellation of any interim approved or approved outage, and the Transmission Owner shall provide such information to the Internal Market Monitor in accordance with the ISO New England Information Policy.

III.A.13.4. Monitoring of Forward Reserve Resources.

The Internal Market Monitor will receive information that will identify Forward Reserve Resources, the Forward Reserve Threshold Price, and the assigned Forward Reserve Obligation. Prior to mitigation of Supply Offers or Demand Bids associated with a Forward Reserve Resource, the Internal Market Monitor shall consult with the Market Participant in accordance with Section III.A.3 of this ***Appendix A***. The Internal Market Monitor and the Market Participant shall consider the impact on meeting any Forward Reserve Obligations in those consultations. If mitigation is imposed, any mitigated offers shall be used in the calculation of qualifying megawatts under Section III.9.6.4 of Market Rule 1.

III.A.13.5. Imposition of Sanctions.

Appendix B of Market Rule 1 sets forth the procedures and standards under which sanctions may be imposed for certain violations of Market Participants' obligations under the ISO New England Filed Documents and other ISO New England System Rules. The Internal Market Monitor shall administer ***Appendix B*** in accordance with the provisions thereof.

III.A.14. Treatment of Supply Offers for Resources Subject to a Cost-of-Service Agreement.

Article 5 of the form of Cost-of-Service Agreement in ***Appendix I*** to Market Rule 1 addresses the monitoring of resources subject to a cost-of-service agreement by the Internal Market Monitor and External Market Monitor. Pursuant to Section 5.2 of Article 5 of the Form of Cost-of-Service Agreement, after consultation with the Lead Market Participant, Supply Offers that exceed Stipulated Variable Cost as determined in the agreement are subject to adjustment by the Internal Market Monitor to Stipulated Variable Cost.

III.A.15. Request for Additional Cost Recovery.

III.A.15.1. Cost Recovery Request Following Capping.

If as a result of an offer being capped under Section III.1.9, a Market Participant believes that it will not recover the fuel and variable operating and maintenance costs of the Resource, as reflected in the offer, for the hours of the Operating Day during which the offer was capped, the Market Participant may, within 20 days of the receipt of the first Invoice issued containing credits or charges for the applicable Operating Day, submit an additional cost recovery request to the Internal Market Monitor.

A request under this Section III.A.15 may seek recovery of additional costs incurred for the duration of the period of time for which the Resource was operated at the cap.

III.A.15.1.1. Timing and Contents of Request.

Within 20 days of the receipt of the first Invoice containing credits or charges for the applicable Operating Day, a Market Participant requesting additional cost recovery under this Section III.A.15.1 shall submit to the Internal Market Monitor a request in writing detailing: (i) the actual fuel and variable operating and maintenance costs for the Resource for the applicable Operating Days, with supporting data, documentation and calculations for those costs; and (ii) an explanation of why the actual costs of operating the Resource exceeded the capped costs.

III.A.15.1.2. Review by Internal Market Monitor.

To evaluate a Market Participant's request, the Internal Market Monitor shall use the data, calculations and explanations provided by the Market Participant to verify the actual fuel and variable operating and maintenance costs for the Resource for the applicable Operating Days, using the same standards and methodologies the Internal Market Monitor uses to evaluate requests to update Reference Levels under Section III.A.3 of Appendix A. To the extent the Market Participant's request warrants additional cost recovery, the Internal Market Monitor shall reflect that adjustment in the Resource's Reference Levels for the period covered by the request. The ISO shall then re-apply the cost verification and capping formulas in Section III.1.9 using the updated Reference Levels to re-calculate the adjustments to the Market Participant's offers required thereunder, and then shall calculate additional cost recovery using the adjusted offer values.

Within 20 days of the receipt of a completed submittal, the Internal Market Monitor shall provide a written response to the Market Participant's request, detailing (i) the extent to which it agrees with the request with supporting explanation, and (ii) a calculation of the additional cost recovery. Changes to

credits and charges resulting from an additional cost recovery request shall be included in the Data Reconciliation Process.

III.A.15.1.3. Cost Allocation.

The ISO shall allocate charges to Market Participants for payment of any additional cost recovery granted under this Section III.A.15.1 in accordance with the cost allocation provisions of Market Rule 1 that otherwise would apply to payments for the services provided based on the Resource's actual dispatch for the Operating Days in question.

III.A.15.2. Section 205 Filing Right.

If either

> (a) as a result of mitigation applied to a Resource under this ***Appendix A*** for all or part of one or more Operating Days, or
>
> (b) in the absence of mitigation, as a result of a request under Section III.A.15.1 being denied in whole or in part,

a Market Participant believes that it will not recover the fuel and variable operating and maintenance costs of the Resource, as reflected in the offer, for the hours of the Operating Day during which the offer was mitigated or the Section III.A.15.1 request was denied, the Market Participant may submit a filing to the Commission seeking recovery of those costs pursuant to Section 205 of the Federal Power Act. For filings to address cost recovery under Section III.A.15.2(a), the filing must be made within sixty days of receipt of the first Invoice issued containing credits or charges for the applicable Operating Day. For filings to address cost recovery under Section III.A.15.2(b), the filing must be made within sixty days of receipt of the first Invoice issued that reflects the denied request for additional cost recovery under Section III.A.15.1.

A request under this Section III.A.15.2 may seek recovery of additional costs incurred during the following periods: (a) if as a result of mitigation, costs incurred for the duration of the mitigation event, and (b) if as a result of having a Section III.A.15.1 request denied, costs incurred for the duration of the period of time addressed in the Section III.A.15.1 request.

III.A.15.2.1. Contents of Filing.

Any Section 205 filing made pursuant to this section shall include: (i) the actual fuel and variable operating and maintenance costs for the Resource for the applicable Operating Days, with supporting data

and calculations for those costs; (ii) an explanation of (a) why the actual costs of operating the Resource exceeded the Reference Level costs or, (b) in the absence of mitigation, why the actual costs of operating the Resource, as reflected in the original offer and to the extent not recovered under Section III.A.15.1, exceeded the costs as reflected in the capped offer; (iii) the Internal Market Monitor's written explanation provided pursuant to Section III.A.15.3; and (iv) all requested regulatory costs in connection with the filing.

III.A.15.2.2. Review by Internal Market Monitor Prior to Filing.

Within twenty days of the receipt of the applicable Invoice, a Market Participant that intends to make a Section 205 filing pursuant to this Section III.A.15.2 shall submit to the Internal Market Monitor the information and explanation detailed in Section III.A.15.2.1 (i) and (ii) that is to be included in the Section 205 filing. Within twenty days of the receipt of a completed submittal, the Internal Market Monitor shall provide a written explanation of the events that resulted in the Section III.A.15.2 request for additional cost recovery. The Market Participant shall include the Internal Market Monitor's written explanation in the Section 205 filing made pursuant to this Section III A.15.2.

III.A.15.2.3. Cost Allocation.

In the event that the Commission accepts a Market Participant's filing for cost recovery under this section, the ISO shall allocate charges to Market Participants for payment of those costs in accordance with the cost allocation provisions of Market Rule 1 that otherwise would apply to payments for the services provided based on the Resource's actual dispatch for the Operating Days in question.

III.A.16. ADR Review of Internal Market Monitor Mitigation Actions.

III.A.16.1. Actions Subject to Review.

A Market Participant may obtain prompt Alternative Dispute Resolution ("ADR") review of any Internal Market Monitor mitigation imposed on a Resource as to which that Market Participant has bidding or operational authority. A Market Participant must seek review pursuant to the procedure set forth in ***Appendix D*** to this Market Rule 1, but in all cases within the time limits applicable to billing adjustment requests. These deadlines are currently specified in the ISO New England Manuals. Actions subject to review are:

- Imposition of a mitigation remedy.

- Continuation of a mitigation remedy as to which a Market Participant has submitted material evidence of changed facts or circumstances. (Thus, after a Market Participant has unsuccessfully challenged imposition of a mitigation remedy, it may challenge the continuation of that mitigation in a subsequent ADR review on a showing of material evidence of changed facts or circumstances.)

III.A.16.2. Standard of Review.

On the basis of the written record and the presentations of the Internal Market Monitor and the Market Participant, the ADR Neutral shall review the facts and circumstances upon which the Internal Market Monitor based its decision and the remedy imposed by the Internal Market Monitor. The ADR Neutral shall remove the Internal Market Monitor's mitigation only if it concludes that the Internal Market Monitor's application of the Internal Market Monitor mitigation policy was clearly erroneous. In considering the reasonableness of the Internal Market Monitor's action, the ADR Neutral shall consider whether adequate opportunity was given to the Market Participant to present information, any voluntary remedies proposed by the Market Participant, and the need of the Internal Market Monitor to act quickly to preserve competitive markets.

III.A.17. Reporting.

III.A.17.1. Data Collection and Retention.

Market Participants shall provide the Internal Market Monitor and External Market Monitor with any and all information within their custody or control that the Internal Market Monitor or External Market Monitor deems necessary to perform its obligations under this ***Appendix A***, subject to applicable confidentiality limitations contained in the ISO New England Information Policy. This would include a Market Participant's cost information if the Internal Market Monitor or External Market Monitor deems it necessary, including start up, no-load and all other actual marginal costs, when needed for monitoring or mitigation of that Market Participant. Additional data requirements may be specified in the ISO New England Manuals. If for any reason the requested explanation or data is unavailable, the Internal Market Monitor and External Market Monitor will use the best information available in carrying out their responsibilities. The Internal Market Monitor and External Market Monitor may use any and all information they receive in the course of carrying out their market monitor and mitigation functions to the extent necessary to fully perform those functions.

Market Participants must provide data and any other information requested by the Internal Market Monitor that the Internal Market Monitor requests to determine:

(a) the opportunity costs associated with Demand Reduction Offers;

(b) the accuracy of Demand Response Baselines;

(c) the method used to achieve a demand reduction, and;

(d) the accuracy of metered demand reported to the ISO.

III.A.17.2. Periodic Reporting by the ISO and Internal Market Monitor.

III.A.17.2.1. Monthly Report.

The ISO will prepare a monthly report, which will be available to the public both in printed form and electronically, containing an overview of the market's performance in the most recent period.

III.A.17.2.2. Quarterly Report.

The Internal Market Monitor will prepare a quarterly report consisting of market data regularly collected by the Internal Market Monitor in the course of carrying out its functions under this ***Appendix A*** and analysis of such market data. Final versions of such reports shall be disseminated contemporaneously to the Commission, the ISO Board of Directors, the Market Participants, and state public utility commissions for each of the six New England states, provided that in the case of the Market Participants and public utility commissions, such information shall be redacted as necessary to comply with the ISO New England Information Policy. The format and content of the quarterly reports will be updated periodically through consensus of the Internal Market Monitor, the Commission, the ISO, the public utility commissions of the six New England States and Market Participants. The entire quarterly report will be subject to confidentiality protection consistent with the ISO New England Information Policy and the recipients will ensure the confidentiality of the information in accordance with state and federal laws and regulations. The Internal Market Monitor will make available to the public a redacted version of such quarterly reports. The Internal Market Monitor, subject to confidentiality restrictions, may decide whether and to what extent to share drafts of any report or portions thereof with the Commission, the ISO, one or more state public utility commission(s) in New England or Market Participants for input and verification before the report is finalized. The Internal Market Monitor shall keep the Market Participants informed of the progress of any report being prepared pursuant to the terms of this ***Appendix A.***

III.A.17.2.3. Reporting on General Performance of the Forward Capacity Market.

The performance of the Forward Capacity Market, including reconfiguration auctions, shall be subject to the review of the Internal Market Monitor. No later than 180 days after the completion of the second Forward Capacity Auction, the Internal Market Monitor shall file with the Commission and post to the ISO's website a full report analyzing the operations and effectiveness of the Forward Capacity Market. Thereafter, the Internal Market Monitor shall report on the functioning of the Forward Capacity Market in its annual markets report in accordance with the provisions of Section III.A.17.2.4 of this ***Appendix A***.

III.A.17.2.4. Annual Review and Report by the Internal Market Monitor.

The Internal Market Monitor will prepare an annual state of the market report on market trends and the performance of the New England Markets and will present an annual review of the operations of the New England Markets. The annual report and review will include an evaluation of the procedures for the determination of energy, reserve and regulation clearing prices, NCPC costs and the performance of the Forward Capacity Market and FTR Auctions. The review will include a public forum to discuss the performance of the New England Markets, the state of competition, and the ISO's priorities for the coming year. In addition, the Internal Market Monitor will arrange a non-public meeting open to appropriate state or federal government agencies, including the Commission and state regulatory bodies, attorneys general, and others with jurisdiction over the competitive operation of electric power markets, subject to the confidentiality protections of the ISO New England Information Policy, to the greatest extent permitted by law.

III.A.17.2.5. Additional Ad Hoc Reporting on Performance and Competiveness of Markets

Commencing on June 1, 2024, in furtherance of its functions under Section III.A.2 of this Appendix A, including without limitation Sections III.A.2.3 (e) and (k) therein, the Internal Market Monitor shall perform independent evaluations and prepare ad hoc reports on the overall competitiveness and performance of the New England Markets or particular aspects of the New England Markets, including the competitiveness and performance of a major market design change. The Internal Market Monitor shall have the sole discretion to determine when to prepare an ad hoc report and may prepare such report on its own initiative or pursuant to a request by the ISO, New England state public utility commissions or one or more Market Participants. However, the Internal Market Monitor will report on the competitiveness and performance of any new major market design change within one to three years, respectively, of the effective date of

operation of the market design change, or as soon as adequate data becomes available. While the Internal Market Monitor may solicit and/or receive input of the External Market Monitor, Market Participants and other stakeholders, including New England state public utility commissions, the methodology and criteria used to conduct its independent analysis shall be at the sole discretion of the Internal Market Monitor. The Internal Market Monitor shall describe its methodology and criteria used in an ad hoc report of its significant findings and, if any, recommendations. The Internal Market Monitor shall file with the Commission and post to the ISO's website a final version of an ad hoc report. Thereafter, the Internal Market Monitor shall continue to report on the competitiveness and performance of any market design change that has been the subject of an ad hoc report in its quarterly and/or annual reports under Sections III.A.17.2.2 and III.A.17.2.4.

III.A.17.3. Periodic Reporting by the External Market Monitor.

The External Market Monitor will perform independent evaluations and prepare annual and ad hoc reports on the overall competitiveness and efficiency of the New England Markets or particular aspects of the New England Markets, including the adequacy of ***Appendix A***. The External Market Monitor shall have the sole discretion to determine whether and when to prepare ad hoc reports and may prepare such reports on its own initiative or pursuant to requests by the ISO, state public utility commissions or one or more Market Participants. Final versions of such reports shall be disseminated contemporaneously to the Commission, the ISO Board of Directors, the Market Participants, and state public utility commissions for each of the six New England states, provided that in the case of the Market Participants and public utility commissions, such information shall be redacted as necessary to comply with the ISO New England Information Policy. Such reports shall, at a minimum, include:

(i) Review and assessment of the practices, market rules, procedures, protocols and other activities of the ISO insofar as such activities, and the manner in which the ISO implements such activities, affect the competitiveness and efficiency of New England Markets.

(ii) Review and assessment of the practices, procedures, protocols and other activities of any independent transmission company, transmission provider or similar entity insofar as its activities affect the competitiveness and efficiency of the New England Markets.

(iii) Review and assessment of the activities of Market Participants insofar as these activities affect the competitiveness and efficiency of the New England Markets.

(iv) Review and assessment of the effectiveness of ***Appendix A*** and the administration of ***Appendix A*** by the Internal Market Monitor for consistency and compliance with the terms of ***Appendix A.***

(v) Review and assessment of the relationship of the New England Markets with any independent transmission company and with adjacent markets.

The External Market Monitor, subject to confidentiality restrictions, may decide whether and to what extent to share drafts of any report or portions thereof with the Commission, the ISO, one or more state public utility commission(s) in New England or Market Participants for input and verification before the report is finalized. The External Market Monitor shall keep the Market Participants informed of the progress of any report being prepared.

III.A.17.4. Other Internal Market Monitor or External Market Monitor Communications With Government Agencies.

III.A.17.4.1. Routine Communications.

The periodic reviews are in addition to any routine communications the Internal Market Monitor or External Market Monitor may have with appropriate state or federal government agencies, including the Commission and state regulatory bodies, attorneys general, and others with jurisdiction over the competitive operation of electric power markets.

III.A.17.4.2. Additional Communications.

The Internal Market Monitor and External Market Monitor are not a regulatory or enforcement agency. However, they will monitor market trends, including changes in Resource ownership as well as market performance. In addition to the information on market performance and mitigation provided in the monthly, quarterly and annual reports the External Market Monitor or Internal Market Monitor shall:

(a) Inform the jurisdictional state and federal regulatory agencies, as well as the Markets Committee, if the External Market Monitor or Internal Market Monitor determines that a market problem appears to be developing that will not be adequately remediable by existing market rules or mitigation measures;

(b) If the External Market Monitor or Internal Market Monitor receives information from any entity regarding an alleged violation of law, refer the entity to the appropriate state or federal agencies;

(c) If the External Market Monitor or Internal Market Monitor reasonably concludes, in the normal course of carrying out its monitoring and mitigation responsibilities, that certain

market conduct constitutes a violation of law, report these matters to the appropriate state and federal agencies; and,

(d) Provide the names of any companies subjected to mitigation under these procedures as well as a description of the behaviors subjected to mitigation and any mitigation remedies or sanctions applied.

III.A.17.4.3. Confidentiality.

Information identifying particular participants required or permitted to be disclosed to jurisdictional bodies under this section shall be provided in a confidential report filed under Section 388.112 of the Commission regulations and corresponding provisions of other jurisdictional agencies. The Internal Market Monitor will include the confidential report with the quarterly submission it provides to the Commission pursuant to Section III.A.17.2.2.

III.A.17.5. Other Information Available from Internal Market Monitor and External Market Monitor on Request by Regulators.

The Internal Market Monitor and External Market Monitor will normally make their records available as described in this paragraph to authorized state or federal agencies, including the Commission and state regulatory bodies, attorneys general and others with jurisdiction over the competitive operation of electric power markets ("authorized government agencies"). With respect to state regulatory bodies and state attorneys general ("authorized state agencies"), the Internal Market Monitor and External Market Monitor shall entertain information requests for information regarding general market trends and the performance of the New England Markets, but shall not entertain requests that are designed to aid enforcement actions of a state agency. The Internal Market Monitor and External Market Monitor shall promptly make available all requested data and information that they are permitted to disclose to authorized government agencies under the ISO New England Information Policy. Notwithstanding the foregoing, in the event an information request is unduly burdensome in terms of the demands it places on the time and/or resources of the Internal Market Monitor or External Market Monitor, the Internal Market Monitor or External Market Monitor shall work with the authorized government agency to modify the scope of the request or the time within which a response is required, and shall respond to the modified request.

The Internal Market Monitor and External Market Monitor also will comply with compulsory process, after first notifying the owner(s) of the items and information called for by the subpoena or civil investigative demand and giving them at least ten Business Days to seek to modify or quash the compulsory process. If an authorized government agency makes a request in writing, other than

compulsory process, for information or data whose disclosure to authorized government agencies is not permitted by the ISO New England Information Policy, the Internal Market Monitor and External Market Monitor shall notify each party with an interest in the confidentiality of the information and shall process the request under the applicable provisions of the ISO New England Information Policy. Requests from the Commission for information or data whose disclosure is not permitted by the ISO New England Information Policy shall be processed under Section 3.2 of the ISO New England Information Policy. Requests from authorized state agencies for information or data whose disclosure is not permitted by the ISO New England Information Policy shall be processed under Section 3.3 of the ISO New England Information Policy. In the event confidential information is ultimately released to an authorized state agency in accordance with Section 3.3 of the ISO New England Information Policy, any party with an interest in the confidentiality of the information shall be permitted to contest the factual content of the information, or to provide context to such information, through a written statement provided to the Internal Market Monitor or External Market Monitor and the authorized state agency that has received the information.

III.A.18. Ethical Conduct Standards.

III.A.18.1. Compliance with ISO New England Inc. Code of Conduct.
The employees of the ISO that perform market monitoring and mitigation services for the ISO and the employees of the External Market Monitor that perform market monitoring and mitigation services for the ISO shall execute and shall comply with the terms of the ISO New England Inc. Code of Conduct attached hereto as ***Exhibit 5***.

III.A.18.2. Additional Ethical Conduct Standards.
The employees of the ISO that perform market monitoring and mitigation services for the ISO and the employees of the External Market Monitor that perform market monitoring and mitigation services for the ISO shall also comply with the following additional ethical conduct standards. In the event of a conflict between one or more standards set forth below and one or more standards contained in the ISO New England Inc. Code of Conduct, the more stringent standard(s) shall control.

III.A.18.2.1. Prohibition on Employment with a Market Participant.
No such employee shall serve as an officer, director, employee or partner of a Market Participant.

III.A.18.2.2. Prohibition on Compensation for Services.

No such employee shall be compensated, other than by the ISO or, in the case of employees of the External Market Monitor, by the External Market Monitor, for any expert witness testimony or other commercial services, either to the ISO or to any other party, in connection with any legal or regulatory proceeding or commercial transaction relating to the ISO or the New England Markets.

III.A.18.2.3. Additional Standards Applicable to External Market Monitor.

In addition to the standards referenced in the remainder of this Section 18 of ***Appendix A***, the employees of the External Market Monitor that perform market monitoring and mitigation services for the ISO are subject to conduct standards set forth in the External Market Monitor Services Agreement entered into between the External Market Monitor and the ISO, as amended from time-to-time. In the event of a conflict between one or more standards set forth in the External Market Monitor Services Agreement and one or more standards set forth above or in the ISO New England Inc. Code of Conduct, the more stringent standard(s) shall control.

III.A.19. Protocols on Referral to the Commission of Suspected Violations.

(A) The Internal Market Monitor or External Market Monitor is to make a non-public referral to the Commission in all instances where the Internal Market Monitor or External Market Monitor has reason to believe that a Market Violation has occurred. While the Internal Market Monitor or External Market Monitor need not be able to prove that a Market Violation has occurred, the Internal Market Monitor or External Market Monitor is to provide sufficient credible information to warrant further investigation by the Commission. Once the Internal Market Monitor or External Market Monitor has obtained sufficient credible information to warrant referral to the Commission, the Internal Market Monitor or External Market Monitor is to immediately refer the matter to the Commission and desist from independent action related to the alleged Market Violation. This does not preclude the Internal Market Monitor or External Market Monitor from continuing to monitor for any repeated instances of the activity by the same or other entities, which would constitute new Market Violations. The Internal Market Monitor or External Market Monitor is to respond to requests from the Commission for any additional information in connection with the alleged Market Violation it has referred.

(B) All referrals to the Commission of alleged Market Violations are to be in writing, whether transmitted electronically, by fax, mail or courier. The Internal Market Monitor or External Market Monitor may alert the Commission orally in advance of the written referral.

(C) The referral is to be addressed to the Commission's Director of the Office of Enforcement, with a copy also directed to both the Director of the Office of Energy Market Regulation and the General Counsel.

(D) The referral is to include, but need not be limited to, the following information

(1) The name(s) of and, if possible, the contact information for, the entity(ies) that allegedly took the action(s) that constituted the alleged Market Violation(s);

(2) The date(s) or time period during which the alleged Market Violation(s) occurred and whether the alleged wrongful conduct is ongoing;

(3) The specific rule or regulation, and/or tariff provision, that was allegedly violated, or the nature of any inappropriate dispatch that may have occurred;

(4) The specific act(s) or conduct that allegedly constituted the Market Violation;

(5) The consequences to the market resulting from the acts or conduct, including, if known, an estimate of economic impact on the market;

(6) If the Internal Market Monitor or External Market Monitor believes that the act(s) or conduct constituted a violation of the anti-manipulation rule of Part 1c of the Commission's Rules and Regulations, 18 C.F.R. Part 1c, a description of the alleged manipulative effect on market prices, market conditions, or market rules;

(7) Any other information the Internal Market Monitor or External Market Monitor believes is relevant and may be helpful to the Commission.

(E) Following a referral to the Commission, the Internal Market Monitor or External Market Monitor is to continue to notify and inform the Commission of any information that the Internal Market Monitor or External Market Monitor learns of that may be related to the referral, but the Internal Market Monitor or External Market Monitor is not to undertake any investigative steps regarding the referral except at the express direction of the Commission or Commission staff.

III.A.20. Protocol on Referrals to the Commission of Perceived Market Design Flaws and Recommended Tariff Changes.

(A) The Internal Market Monitor or External Market Monitor is to make a referral to the Commission in all instances where the Internal Market Monitor or External Market Monitor has reason to believe market design flaws exist that it believes could effectively be remedied by rule or tariff changes. The Internal Market Monitor or External Market Monitor must limit distribution of its identifications and recommendations to the ISO and to the Commission in the event it believes broader dissemination could lead to exploitation, with an explanation of why further dissemination should be avoided at that time.

(B) All referrals to the Commission relating to perceived market design flaws and recommended tariff changes are to be in writing, whether transmitted electronically, by fax, mail, or courier. The Internal Market Monitor or External Market Monitor may alert the Commission orally in advance of the written referral.

(C) The referral should be addressed to the Commission's Director of the Office of Energy Market Regulation, with copies directed to both the Director of the Office of Enforcement and the General Counsel.

(D) The referral is to include, but need not be limited to, the following information.

(1) A detailed narrative describing the perceived market design flaw(s);

(2) The consequences of the perceived market design flaw(s), including, if known, an estimate of economic impact on the market;

(3) The rule or tariff change(s) that the Internal Market Monitor or External Market Monitor believes could remedy the perceived market design flaw;

(4) Any other information the Internal Market Monitor or External Market Monitor believes is relevant and may be helpful to the Commission.

(E) Following a referral to the Commission, the Internal Market Monitor or External Market Monitor is to continue to notify and inform the Commission of any additional information regarding the perceived market design flaw, its effects on the market, any additional or modified observations concerning the rule or tariff changes that could remedy the perceived design flaw, any recommendations made by the Internal Market Monitor or External Market Monitor to the regional transmission organization or independent system operator, stakeholders, market participants or state commissions regarding the perceived design flaw, and any actions taken by the regional transmission organization or independent system operator regarding the perceived design flaw.

III.A.21. Review of Offers From New Resources in the Forward Capacity Market.

The Internal Market Monitor shall review offers from new resources in the Forward Capacity Auction as described in this Section III.A.21.

III.A.21.1. Offer Review Trigger Prices.

For each new technology type, the Internal Market Monitor shall establish an Offer Review Trigger Price. Offers in the Forward Capacity Auction at prices that are equal to or above the relevant Offer Review Trigger Price will not be subject to further review by the Internal Market Monitor. A request to submit offers in the Forward Capacity Auction at prices that are below the relevant Offer Review Trigger Price must be submitted in advance of the Forward Capacity Auction as described in Sections III.13.1.1.2.2.3,

III.13.1.3.5 or III.13.1.4.1.1.2.8 and shall be reviewed by the Internal Market Monitor as described in this Section III.A.21.

III.A.21.1.1. Offer Review Trigger Prices for the Forward Capacity Auction.

For resources other than New Import Capacity Resources, the Offer Review Trigger Prices for the twelfth Forward Capacity Auction (for the Capacity Commitment Period beginning on June 1, 2021) shall be as follows:

Generating Capacity Resources	
Technology Type	**Offer Review Trigger Price ($/kW-month)**
combustion turbine	$6.503
combined cycle gas turbine	$7.856
on-shore wind	$11.025

Demand Capacity Resources - Commercial and Industrial	
Technology Type	**Offer Review Trigger Price ($/kW-month)**
Load Management and/or previously installed Distributed Generation	$1.008
new Distributed Generation	based on generation technology type
Energy Efficiency	$0.000

Demand Capacity Resources – Residential	
Technology Type	**Offer Review Trigger Price ($/kW-month)**
Load Management	$7.559
previously installed Distributed Generation	$1.008
new Distributed Generation	based on generation technology type
Energy Efficiency	$0.000

Other Resources	
All other technology types	Forward Capacity Auction Starting Price

Where a new resource is composed of assets having different technology types, the resource's Offer Review Trigger Price will be calculated in accordance with the weighted average formula in Section III.A.21.2(c).

For purposes of determining the Offer Review Trigger Price of a Demand Capacity Resource composed in whole or in part of Distributed Generation, the Distributed Generation is considered new, rather than previously installed, if (1) the Project Sponsor for the New Demand Capacity Resource has participated materially in the development, installation or funding of the Distributed Generation during the five years prior to commencement of the Capacity Commitment Period for which the resource is being qualified for participation, and (2) the Distributed Generation has not been assigned to a Demand Capacity Resource with a Capacity Supply Obligation in a prior Capacity Commitment Period.

For a New Import Capacity Resource that is backed by a single new External Resource and that is associated with an investment in transmission that increases New England's import capability, the Offer Review Trigger Prices in the table above shall apply, based on the technology type of the External Resource; provided that, if a New Import Capacity Resource is associated with an Elective Transmission Upgrade, it shall have an Offer Review Trigger Price of the Forward Capacity Auction Starting Price plus $0.01/kW-month.

For any other New Import Capacity Resource, the Offer Review Trigger Price shall be the Forward Capacity Auction Starting Price plus $0.01/kW-month.

III.A.21.1.2. Calculation of Offer Review Trigger Prices.

(a) The Offer Review Trigger Price for each of the technology types listed above shall be recalculated using updated data for the Capacity Commitment Period beginning on June 1, 2025 and no less often than once every three years thereafter. Where any Offer Review Trigger Price is recalculated, the Internal Market Monitor will review the results of the recalculation with stakeholders and the new Offer Review Trigger Price shall be filed with the Commission prior to the Forward Capacity Auction in which the Offer Review Trigger Price is to apply.

(b) For New Generating Capacity Resources, the methodology used to recalculate the Offer Review Trigger Price pursuant to subsection (a) above is as follows. Capital costs, expected non-capacity revenues and operating costs, assumptions regarding depreciation, taxes and discount rate are input into a capital budgeting model which is used to calculate the break-even contribution required from the Forward

Capacity Market to yield a discounted cash flow with a net present value of zero for the project. The Offer Review Trigger Price is set equal to the year-one capacity price output from the model. The model looks at 20 years of real-dollar cash flows discounted at a rate (Weighted Average Cost of Capital) consistent with that expected of a project whose output is under contract (i.e., a contract negotiated at arm's length between two unrelated parties).

(c) For New Demand Capacity Resources comprised of Energy Efficiency, the methodology used to recalculate the Offer Review Trigger Price pursuant to subsection (a) above shall be the same as that used for New Generating Capacity Resources, with the following exceptions. First, the model takes account of all costs incurred by the utility and end-use customer to deploy the efficiency measure. Second, rather than energy revenues, the model recognizes end-use customer savings associated with the efficiency programs. Third, the model assumes that all costs are expensed as incurred. Fourth, the benefits realized by end-use customers are assumed to have no tax implications for the utility. Fifth, the model discounts cash flows over the Measure Life of the energy efficiency measure.

(d) For New Demand Capacity Resources other than Demand Capacity Resources comprised of Energy Efficiency, the methodology used to recalculate the Offer Review Trigger Price pursuant to subsection (a) above is the same as that used for New Generating Capacity Resources, except that the model discounts cash flows over the contract life. For Demand Capacity Resources (other than those comprised of Energy Efficiency) that are composed primarily of large commercial or industrial customers that use pre-existing equipment or strategies, incremental costs include new equipment costs and annual operating costs such as customer incentives and sales representative commissions. For Demand Capacity Resources (other than Demand Capacity Resources comprised of Energy Efficiency) primarily composed of residential or small commercial customers that do not use pre-existing equipment or strategies, incremental costs include equipment costs, customer incentives, marketing, sales, and recruitment costs, operations and maintenance costs, and software and network infrastructure costs.

(e) For years in which no full recalculation is performed pursuant to subsection (a) above, the Offer Review Trigger Prices will be adjusted as follows:

(1) Each line item associated with capital costs that is included in the capital budgeting model will be associated with the indices included in the table below:

Cost Component	**Index**
gas turbines	BLS-PPI "Turbines and Turbine Generator Sets"

steam turbines	BLS-PPI "Turbines and Turbine Generator Sets"
wind turbines	Bloomberg Wind Turbine Price Index
Other Equipment	BLS-PPI "General Purpose Machinery and Equipment"
construction labor	BLS “Quarterly Census of Employment and Wages” 2371 Utility System Construction Average Annual Pay: – Combustion turbine and combined cycle gas turbine costs to be indexed to values corresponding to the location of Hampden County, Massachusetts – On-shore wind costs to be indexed to values corresponding to the location of Cumberland County, Maine
other labor	BLS “Quarterly Census of Employment and Wages” 2211 Power Generation and Supply Average Annual Pay: – Combustion turbine and combined cycle gas turbine costs to be indexed to values corresponding to the location of Hampden County, Massachusetts – On-shore wind costs to be indexed to values corresponding to the location of Cumberland County, Maine
materials	BLS-PPI "Materials and Components for Construction"
electric interconnection	BLS - PPI "Electric Power Transmission, Control, and Distribution"
gas interconnection	BLS - PPI "Natural Gas Distribution: Delivered to ultimate consumers for the account of others (transportation only)”
fuel inventories	Federal Reserve Bank of St. Louis “Gross Domestic Product: Implicit Price Deflator (GDPDEF)”

(2) Each line item associated with fixed operating and maintenance costs that is included in the capital budgeting model will be associated with the indices included in the table below:

Cost Component	**Index**
labor, administrative and general	BLS “Quarterly Census of Employment and Wages” 2211 Power Generation and Supply Average Annual Pay: – Combustion turbine and combined cycle gas turbine costs to be indexed to values corresponding to the location of Hampden County, Massachusetts – On-shore wind costs to be indexed to values corresponding to the location of Cumberland County, Maine
materials and contract services	BLS-PPI "Materials and Components for Construction"
site leasing costs	Federal Reserve Bank of St. Louis “Gross Domestic Product: Implicit Price Deflator (GDPDEF)”

(3) For each line item in (1) and (2) above, the ISO shall calculate a multiplier that is equal to the average of values published during the most recent 12 month period available at the time of making the adjustment divided by the average of the most recent 12 month period available at the time of establishing the Offer Review Trigger Prices for the FCA reflected in the table in Section III.A.21.1.1 above. The value of each line item associated with capital costs and fixed operating and maintenance costs included

in the capital budgeting model for the FCA reflected in the table in Section A.21.1.1 above will be adjusted by the relevant multiplier.

(4) The energy and ancillary services offset values for each technology type in the capital budgeting model shall be adjusted by inputting to the capital budgeting model the most recent Henry Hub natural gas futures prices, the Algonquin Citygates Basis natural gas futures prices and the Massachusetts Hub On-Peak electricity prices for the months in the Capacity Commitment Period beginning June 1, 2021, as published by ICE.

(5) Renewable energy credit values in the capital budgeting model shall be updated based on the most recent MA Class 1 REC price for the vintage closest to the first year of the Capacity Commitment Period associated with the relevant FCA as published by SNL Financial.

(6) The capital budgeting model and the Offer Review Trigger Prices adjusted pursuant to this subsection (e) will be published on the ISO's web site.

(7) If any of the values required for the calculations described in this subsection (e) are unavailable, then comparable values, prices or sources shall be used.

III.A.21.2. New Resource Offer Floor Prices and Offer Prices.

For every new resource participating in a Forward Capacity Auction, the Internal Market Monitor shall determine a New Resource Offer Floor Price or offer prices, as described in this Section III.A.21.2.

(a) For a Lead Market Participant with a New Capacity Resource that does not submit a request to submit offers in the Forward Capacity Auction at prices that are below the relevant Offer Review Trigger Price as described in Sections III.13.1.1.2.2.3, III.13.1.3.5 or III.13.1.4.1.1.2.8, the New Resource Offer Floor Price shall be calculated as follows:

> For a New Import Capacity Resource (other than a New Import Capacity Resource that is (i) backed by a single new External Resource and that is associated with an investment in transmission that increases New England's import capability or (ii) associated with an Elective Transmission Upgrade) the New Resource Offer Floor Price shall be $0.00/kW-month.

For a New Generating Capacity Resource, New Import Capacity Resource that is backed by a single new External Resource and that is associated with an investment in transmission that increases New England's import capability, New Import Capacity Resource that is associated with an Elective Transmission Upgrade, and New Demand Capacity Resource, the New Resource Offer Floor Price shall be equal to the applicable Offer Review Trigger Price.

A resource having a New Resource Offer Floor Price higher than the Forward Capacity Auction Starting Price shall not be included in the Forward Capacity Auction.

(b) For a Lead Market Participant with a New Capacity Resource that does submit a request to submit offers in the Forward Capacity Auction at prices that are below the relevant Offer Review Trigger Price as described in Sections III.13.1.1.2.2.3, III.13.1.3.5 and III.13.1.4.1.1.2.8, the resource's New Resource Offer Floor Price and offer prices in the case of a New Import Capacity Resource (other than a New Import Capacity Resource that is backed by a single new External Resource and that is associated with an investment in transmission that increases New England's import capability or a New Import Capacity Resource that is associated with an Elective Transmission Upgrade) shall be calculated as follows:

For a New Import Capacity Resource that is subject to the pivotal supplier test in Section III.A.23 and is found not to be associated with a pivotal supplier as determined pursuant to Section III.A.23, the resource's New Resource Offer Floor Price and offer prices shall be equal to the lower of (i) the requested offer price submitted to the ISO as described in Sections III.13.1.1.2.2.3 and III.13.1.3.5; or (ii) the price revised pursuant to Section III.13.1.3.5.7.

For any other New Capacity Resource, the Internal Market Monitor shall enter all relevant resource costs and non-capacity revenue data, as well as assumptions regarding depreciation, taxes, and discount rate into the capital budgeting model used to develop the relevant Offer Review Trigger Price and shall calculate the break-even contribution required from the Forward Capacity Market to yield a discounted cash flow with a net present value of zero for the project. The Internal Market Monitor shall compare the requested offer price to this capacity price estimate and the resource's New Resource Offer Floor Price and offer prices shall be determined as follows:

(i) The Internal Market Monitor will exclude any out-of-market revenue sources from the cash flows used to evaluate the requested offer price. Out-of-market revenues are any revenues that are: (a) not tradable throughout the New England Control Area or that are restricted to resources

within a particular state or other geographic sub-region; or (b) not available to all resources of the same physical type within the New England Control Area, regardless of the resource owner. Expected revenues associated with economic development incentives that are offered broadly by state or local government and that are not expressly intended to reduce prices in the Forward Capacity Market are not considered out-of-market revenues for this purpose. In submitting its requested offer price, the Project Sponsor shall indicate whether and which project cash flows are supported by a regulated rate, charge, or other regulated cost recovery mechanism. If the project is supported by a regulated rate, charge, or other regulated cost recovery mechanism, then that rate will be replaced with the Internal Market Monitor estimate of energy revenues. Where possible, the Internal Market Monitor will use like-unit historical production, revenue, and fuel cost data. Where such information is not available (e.g., there is no resource of that type in service), the Internal Market Monitor will use a forecast provided by a credible third party source. The Internal Market Monitor will review capital costs, discount rates, depreciation and tax treatment to ensure that it is consistent with overall market conditions. Any assumptions that are clearly inconsistent with prevailing market conditions will be adjusted.

(ii) For a New Demand Capacity Resource, the resource's costs shall include all expenses, including incentive payments, equipment costs, marketing and selling and administrative and general costs incurred to acquire and/or develop the Demand Capacity Resource. Revenues shall include all non-capacity payments expected from the ISO-administered markets made for services delivered from the associated Demand Response Resource, and expected costs avoided by the associated end-use customer as a direct result of the installation or implementation of the associated Asset(s).

(iii) For a New Capacity Resource that has achieved commercial operation prior to the New Capacity Qualification Deadline for the Forward Capacity Auction in which it seeks to participate, the relevant capital costs to be entered into the capital budgeting model will be the undepreciated original capital costs adjusted for inflation. For any such resource, the prevailing market conditions will be those that were in place at the time of the decision to construct the resource.

(iv) Sufficient documentation and information must be included in the resource's qualification package to allow the Internal Market Monitor to make the determinations described in this subsection (b). Such documentation should include all relevant financial estimates and cost

projections for the project, including the project's pro-forma financing support data. For a New Import Capacity Resource, such documentation should also include the expected costs of purchasing power outside the New England Control Area (including transaction costs and supported by forward power price index values or a power price forecast for the applicable Capacity Commitment Period), expected transmission costs outside the New England Control Area, and expected transmission costs associated with importing to the New England Control Area, and may also include reasonable opportunity costs and risk adjustments. For a new capacity resource that has achieved commercial operation prior to the New Capacity Qualification Deadline, such documentation should also include all relevant financial data of actual incurred capital costs, actual operating costs, and actual revenues since the date of commercial operation. If the supporting documentation and information required by this subsection (b) is deficient, the Internal Market Monitor, at its sole discretion, may consult with the Project Sponsor to gather further information as necessary to complete its analysis. If after consultation, the Project Sponsor does not provide sufficient documentation and information for the Internal Market Monitor to complete its analysis, then the resource's New Resource Offer Floor Price shall be equal to the Offer Review Trigger Price.

(v) If the Internal Market Monitor determines that the requested offer prices are consistent with the Internal Market Monitor's capacity price estimate, then the resource's New Resource Offer Floor Price shall be equal to the requested offer price, subject to the provisions of subsection (vii) concerning New Import Capacity Resources.

(vi) If the Internal Market Monitor determines that the requested offer prices are not consistent with the Internal Market Monitor's capacity price estimate, then the resource's offer prices shall be set to a level that is consistent with the capacity price estimate, as determined by the Internal Market Monitor. Any such determination will be explained in the resource's qualification determination notification and will be filed with the Commission as part of the filing described in Section III.13.8.1(c), subject to the provisions of subsection (vii) concerning New Import Capacity Resources.

(vii) For New Import Capacity Resources that have been found to be associated with a pivotal supplier as determined pursuant to Section III.A.23, if the supplier elects to revise the requested offer prices pursuant to Section III.13.1.3.5.7 to values that are below the Internal Market

Monitor's capacity price estimate established pursuant to subsection (v) or (vi), then the resource's offer prices shall be equal to the revised offer prices.

(c) For a new capacity resource composed of assets having different technology types the Offer Review Trigger Price shall be the weighted average of the Offer Review Trigger Prices of the asset technology types of the assets that comprise the resource, based on the expected capacity contribution from each asset technology type. Sufficient documentation must be included in the resource's qualification package to permit the Internal Market Monitor to determine the weighted average Offer Review Trigger Price.

III.A.22. [Reserved.]

III.A.23. Pivotal Supplier Test for Existing Capacity Resources and New Import Capacity Resources in the Forward Capacity Market.

III.A.23.1. Pivotal Supplier Test.

The pivotal supplier test is performed prior to the commencement of the Forward Capacity Auction at the system level and for each import-constrained Capacity Zone.

An Existing Capacity Resource or New Import Capacity Resource is associated with a pivotal supplier if, after removing all the supplier's FCA Qualified Capacity, the ability to meet the relevant requirement is less than the requirement. Only those New Import Capacity Resources that are not (i) backed by a single new External Resource and associated with an investment in transmission that increases New England's import capability, or (ii) associated with an Elective Transmission Upgrade, are subject to the pivotal supplier test.

For the system level determination, the relevant requirement is the Installed Capacity Requirement (net of HQICCs). For each import-constrained Capacity Zone, the relevant requirement is the Local Sourcing Requirement for that import-constrained Capacity Zone.

At the system level, the ability to meet the relevant requirement is the sum of the following:

(a) The total FCA Qualified Capacity from all Existing Generating Capacity Resources and Existing Demand Capacity Resources in the Rest-of-Pool Capacity Zone;

(b) For each modeled import-constrained Capacity Zone, the greater of:

(1) the total FCA Qualified Capacity from all Existing Generating Capacity Resources and Existing Demand Capacity Resources within the import-constrained Capacity Zone plus, for each modeled external interface connected to the import-constrained Capacity Zone, the lesser of: (i) the capacity transfer limit of the interface (net of tie benefits), and; (ii) the total amount of FCA Qualified Capacity from Import Capacity Resources over the interface, and;

(2) the Local Sourcing Requirement of the import-constrained Capacity Zone;

(c) For each modeled nested export-constrained Capacity Zone, the lesser of:

(1) the total FCA Qualified Capacity from all Existing Generating Capacity Resources and Existing Demand Capacity Resources within the nested export-constrained Capacity Zone plus, for each external interface connected to the nested export-constrained Capacity Zone, the lesser of: (i) the capacity transfer limit of the interface (net of tie benefits), and; (ii) the total amount of FCA Qualified Capacity from Import Capacity Resources over the interface, and;

(2) the Maximum Capacity Limit of the nested export-constrained Capacity Zone;

(d) For each modeled export-constrained Capacity Zone that is not a nested export-constrained Capacity Zone, the lesser of:

(1) the total FCA Qualified Capacity from all Existing Generating Capacity Resources and Existing Demand Capacity Resources within the export-constrained Capacity Zone, excluding the total FCA Qualified Capacity from Existing Generating Capacity Resources and Existing Demand Capacity Resources within a nested export-constrained Capacity Zone, plus, for each external interface connected to the export-constrained Capacity Zone that is not included in any nested export-constrained Capacity Zone, the lesser of: (i) the capacity transfer limit of the interface (net of tie benefits), and; (ii) the total amount of FCA Qualified Capacity from Import Capacity Resources over the interface, excluding the contribution from any nested export-constrained Capacity Zone as determined pursuant to Section III.A.23.1(c), and;

(2) the Maximum Capacity Limit of the export-constrained Capacity Zone minus the contribution from any associated nested export-constrained Capacity Zone as determined pursuant to Section III.A.23.1(c), and;

(e) For each modeled external interface connected to the Rest-of-Pool Capacity Zone, the lesser of:

(1) the capacity transfer limit of the interface (net of tie benefits), and;

(2) the total amount of FCA Qualified Capacity from Import Capacity Resources over the interface.

For each import-constrained Capacity Zone, the ability to meet the relevant requirement is the sum of the following:

(1) The total FCA Qualified Capacity from all Existing Generating Capacity Resources and Existing Demand Capacity Resources located within the import-constrained Capacity Zone; and
(2) For each modeled external interface connected to the import-constrained Capacity Zone, the lesser of: (1) the capacity transfer limit of the interface (net of tie benefits), and; (2) the total amount of FCA Qualified Capacity from Import Capacity Resources over the interface.

III.A.23.2. Conditions Under Which Capacity is Treated as Non-Pivotal.

FCA Qualified Capacity of a supplier that is determined to be pivotal under Section III.A.23.1 is treated as non-pivotal under the following four conditions:

(a) If the removal of a supplier's FCA Qualified Capacity in an export-constrained Capacity Zone or nested export-constrained Capacity Zone does not change the quantity calculated in Section III.A.23.1(c) for that export-constrained Capacity Zone or nested export-constrained Capacity Zone, then that capacity is treated as capacity of a non-pivotal supplier.
(b) If the removal of a supplier's FCA Qualified Capacity in the form of Import Capacity Resources at an external interface does not change the quantity calculated in Section III.A.23.1(d) for that interface, then that capacity is treated as capacity of a non-pivotal supplier.
(c) If the removal of a supplier's FCA Qualified Capacity in the form of Import Capacity Resources at an external interface connected to an import-constrained Capacity Zone does not change the quantity calculated in Section III.A.23.1(f) for that interface, then that capacity is treated as capacity of a non-pivotal supplier.
(d) If a supplier whose only FCA Qualified Capacity is a single capacity resource with a bid that (i) is not subject to rationing under Section III.13.1.2.3.1 or III.13.2.6, and (ii) contains only one price-quantity pair for the entire FCA Qualified Capacity amount, then the capacity of that resource is treated as capacity of a non-pivotal supplier.

III.A.23.3. Pivotal Supplier Test Notification of Results.

Results of the pivotal supplier test will be made available to suppliers no later than seven days prior to the start of the Forward Capacity Auction.

III.A.23.4. Qualified Capacity for Purposes of Pivotal Supplier Test.

For purposes of the tests performed in Sections III.A.23.1 and III.A.23.2, the FCA Qualified Capacity of a supplier includes the capacity of Existing Generating Capacity Resources, Existing Demand Capacity Resources, Existing Import Capacity Resources, and New Import Capacity Resources (other than (i) a New Import Capacity Resource that is backed by a single new External Resource and that is associated with an investment in transmission that increases New England's import capability; and (ii) a New Import Capacity Resource associated with an Elective Transmission Upgrade) that is controlled by the supplier or its Affiliates.

For purposes of determining the ability to meet the relevant requirement under Section III.A.23.1, the FCA Qualified Capacity from New Import Capacity Resources does not include (i) any New Import Capacity Resource that is backed by a single new External Resource and that is associated with an investment in transmission that increases New England's import capability; and (ii) any New Import Capacity Resource associated with an Elective Transmission Upgrade.

For purposes of determining the FCA Qualified Capacity of a supplier or its Affiliates under Section III.A.23.4, "control" or "controlled" means the possession, directly or indirectly, of the authority to direct the decision-making regarding how capacity is offered into the Forward Capacity Market, and includes control by contract with unaffiliated third parties. In complying with Section I.3.5 of the ISO Tariff, a supplier shall inform the ISO of all capacity that it and its Affiliates control under this Section III.A.23.4 and all capacity the control of which it has contracted to a third party.

III.A.24. Retirement Portfolio Test for Existing Capacity Resources in the Forward Capacity Market.

The retirement portfolio test is performed prior to the commencement of the Forward Capacity Auction for each Lead Market Participant submitting a Permanent De-List Bid or Retirement De-List Bid. The test will be performed as follows:

If

i. The annual capacity revenue from the Lead Market Participant's total FCA Qualified Capacity, not including the FCA Qualified Capacity associated with the Permanent De-List Bid or Retirement De-List Bid, is greater than

ii. the annual capacity revenue from the Lead Market Participant's total FCA Qualified Capacity, including the FCA Qualified Capacity associated with the Permanent De-List Bid or Retirement De-List Bid, then

iii. the Lead Market Participant will be found to have a portfolio benefit pursuant to the retirement portfolio test.

Where,

iv. the Lead Market Participant's annual capacity revenue from the Lead Market Participant's total FCA Qualified Capacity not including the FCA Qualified Capacity associated with the Permanent De-List Bid or Retirement De-List Bid is calculated as the product of (a) the Lead Market Participant's total FCA Qualified Capacity not including the FCA Qualified Capacity associated with the Permanent De-List Bid or Retirement De-List Bid and (b) the Internal Market Monitor-estimated capacity clearing price not including the FCA Qualified Capacity associated with the Permanent De-List Bid or Retirement De-List Bid.

v. The Lead Market Participant's annual capacity revenue from the Lead Market Participant's total FCA Qualified Capacity including the FCA Qualified Capacity associated with the Permanent De-List Bid or Retirement De-List Bid is calculated as the product of (a) the Lead Market Participant's total FCA Qualified Capacity including the FCA Qualified Capacity associated with the Permanent De-List Bid or Retirement De-List Bid and (b) the Internal Market Monitor-estimated capacity clearing price including the FCA Qualified Capacity associated with the Permanent De-List Bid or Retirement De-List Bid.

vi. The Internal Market Monitor-estimated capacity clearing price, not to exceed the Forward Capacity Auction Starting Price, is based on the parameters of the System-Wide Capacity Demand Curve and Capacity Zone Demand Curves as specified in Section III.13.2.2.

For purposes of the test performed in this Section III.A.24, the FCA Qualified Capacity of a Lead Market Participant includes the capacity of Existing Capacity Resources that is controlled by the Lead Market Participant or its Affiliates.

For purposes of determining the FCA Qualified Capacity of a Lead Market Participant or its Affiliates under this Section III.A.24, “control” or “controlled” means the possession, directly or indirectly, of the authority to direct the decision-making regarding how capacity is offered into the Forward Capacity Market, and includes control by contract with unaffiliated third parties. In complying with Section I.3.5 of the ISO Tariff, a Lead Market Participant shall inform the ISO of all capacity that it and its Affiliates control under this Section III.A.4 and all capacity the control of which it has contracted to a third party.

APPENDIX K

INVENTORIED ENERGY PROGRAM

III.K Inventoried Energy Program

For the winter~~s~~ of 2023-2024~~ and 2024-2025~~ (the "relevant winter period"), the ISO shall administer an inventoried energy program in accordance with the provisions of this Appendix K.

III.K.1. Submission of Election Information

Participation in the inventoried energy program is voluntary. To participate in both the forward and spot components of the program, the information listed in this Section III.K.1 must be submitted to the ISO no later than the October 1 immediately preceding the start of the relevant winter ~~(a separate election submission must be made for each winter)~~ and must reflect an ability to provide the submitted inventoried energy throughout the relevant winter period. To participate in the spot component of the program only, the information listed in this Section III.K.1 may be submitted to the ISO through the end of the relevant winter period, in which case participation will begin (prospectively only) upon review and approval by the ISO of the information submitted.

(a) A list of the Market Participant's assets that will participate in the inventoried energy program, with a description for each such asset of: the Market Participant's Ownership Share in the asset; the types of fuel it can use; the approximate maximum amount of each fuel type that can be stored on site (and in upstream ponds) or, in the case of natural gas, the amount that is subject to a contract meeting the requirements described in Section III.K.1(a)(iii), as measured pursuant to the provisions of Section III.K.3.2.1.1(a); and a list of other assets at the same facility that share the fuel inventory (or, in the case of natural gas, a list of assets at the same or any other facility that can also take fuel pursuant to the same contract).

(i) The following asset types may not be included in a Market Participant's list of assets: Settlement Only Resources; assets not located in the New England Control Area; assets being compensated pursuant to a cost-of-service agreement (as described in Section III.13.2.5.2.5) during the relevant winter period; and assets that cannot operate on stored fuel (or natural gas subject to a contract as described in Section III.K.1(a)(iii)) at the ISO's direction.

(ii) A Demand Response Resource with Distributed Generation may be included in a Market Participant's list of assets.

(iii) For any asset listed that will participate in the inventoried energy program using natural gas as a fuel type, the Market Participant must also submit an executed contract for firm delivery of natural gas. Any such contract must include no limitations on when natural gas can be called during a day, and must specify the parties to the contract, the volume of gas to be delivered, the price to be paid for that gas, the pipeline delivery point name and gas meter number of the listed asset, terms related to pipeline transportation to the meter of the listed asset (with indication of whether the gas supplier or another entity is providing the transportation), and all other terms, conditions, or related agreements affecting whether and when gas will be delivered, the volume of gas to be delivered, and the price to be paid for that gas.

(b) A detailed description of how the Market Participant's energy inventory will be measured after each Inventoried Energy Day in accordance with the provisions of Section III.K.3.2.1.1 and converted to MWh (including the rates at which fuel is converted to energy for each asset). Where assets share fuel inventory, if the Market Participant believes that fuel should be allocated among those assets in a manner other than the default approach described in Section III.K.3.2.1.1(e)(ii), this description should explain and support that alternate allocation.

(c) Whether the Market Participant is electing to participate in only the spot component of the inventoried energy program or in both the forward and spot components.

(d) If electing to participate in both the forward and spot components of the program, the total MWh value for which the Market Participant elects to be compensated at the forward rate (the "Forward Energy Inventory Election"). This MWh value must be less than or equal to the combined MW output that the assets listed by the Market Participant (adjusted to account for Ownership Share) could provide over a period of 72 hours, as limited by the maximum amount of each fuel type that can be stored on site (and in upstream ponds) for each asset and as limited by the terms of any natural gas contracts submitted pursuant to Section III.K.1(a)(iii). If the Market Participant is submitting one or more contracts for natural gas, the Market Participant must indicate whether any of the suppliers listed in those contracts have the capability to deliver vaporized liquefied natural gas to New England, and if so, what portion of its Forward Energy Inventory Election, in MWh, should be attributed to liquefied natural gas (the "Forward LNG Inventory Election"). (For Market Participants electing to participate in only the spot component of the program, the Forward Energy Inventory Election and Forward LNG Inventory Election shall be zero.)

III.K.1.1 ISO Review and Approval of Election Information

The ISO will review each Market Participant's election submission, and may confer with the Market Participant to clarify or supplement the information provided. The ISO shall modify the amounts as necessary to ensure consistency with asset-specific operational characteristics, terms and conditions associated with submitted contracts, regulatory restrictions, and the requirements of the inventoried energy program. For election information that is submitted no later than October 1, the ISO will report the final program participation values to the Market Participant by the November 1 immediately preceding the start of the relevant winter, and participation will begin on December 1. For election information that is submitted after October 1 (spot component participation only), the ISO will, as soon as practicable, report the final program participation values and the date that participation will begin to the Market Participant.

(a) In performing this review, the ISO shall reject all or any portions of a contract for natural gas that:

(i) does not meet the requirements of Section III.K.1(a)(iii); or

(ii) requires (except in the case of an asset that is supplied from a liquefied natural gas facility adjacent and directly connected to the asset) the Market Participant to incur incremental costs to exercise the contract that may be greater than 250 percent of the average of the sum of the monthly Henry Hub natural gas futures prices and the Algonquin Citygates Basis natural gas futures prices for the December, January, and February of the relevant winter period on the earlier of the day the contract is executed and the first Business Day in October prior to that winter period.

(b) In performing this review, if the total of the Forward LNG Inventory Elections from all participating Market Participants (excluding amounts to be supplied to an asset from a liquefied natural gas facility adjacent and directly connected to the asset) exceeds 560,000 MWh, the ISO shall prorate each such Forward LNG Inventory Election such that the sum of such Forward LNG Inventory Elections is no greater than 560,000 MWh, and each Market Participant's Forward Energy Inventory Election shall be adjusted accordingly.

III.K.1.2 Posting of Forward Energy Inventory Election Amount

As soon as practicable after the November 1 immediately preceding the start of the relevant winter, the ISO will post to its website the total amount of Forward Energy Inventory Elections and Forward LNG Inventory Elections participating in the inventoried energy program for that winter.

III.K.2 Inventoried Energy Base Payments

A Market Participant participating in the forward and spot components of the inventoried energy program shall receive a base payment for each day of the months of December, January, and February. Each such base payment shall be equal to the Market Participant's Forward Energy Inventory Election (adjusted as described in Section III.K.1.1) multiplied by $82.49 per MWh and divided by the total number of days in those three months.

III.K.3 Inventoried Energy Spot Payments

A Market Participant participating in the spot component of the inventoried energy program (whether or not the Market Participant is also participating in the forward component of the program) shall receive a spot payment for each Inventoried Energy Day as calculated pursuant to this Section III.K.3.

III.K.3.1 Definition of Inventoried Energy Day

An Inventoried Energy Day shall exist for any Operating Day that occurs in the months of December, January, or February and for which the average of the high temperature and the low temperature on that Operating Day, as measured and reported by the National Weather Service at Bradley International Airport in Windsor Locks, Connecticut, is less than or equal to 17 degrees Fahrenheit.

III.K.3.2 Calculation of Inventoried Energy Spot Payment

A Market Participant's spot payment for an Inventoried Energy Day, which may be positive or negative, shall equal the Market Participant's Real-Time Energy Inventory minus its Forward Energy Inventory Election, with the difference multiplied by $8.25 per MWh.

III.K.3.2.1 Calculation of Real-Time Energy Inventory

A Market Participant's Real-Time Energy Inventory for an Inventoried Energy Day shall be the sum of the Real-Time Energy Inventories for each of the Market Participant's assets participating in the program (adjusted as described in Section III.K.3.2.1.2); provided, however, that where more than one Market Participant has an Ownership Share in an asset, the asset's Real-Time Energy Inventory will be apportioned based on each Market Participant's Ownership Share.

III.K.3.2.1.1 Asset-Level Real-Time Energy Inventory

Each asset's Real-Time Energy Inventory will be determined as follows:

(a) The Market Participant must measure and report to the ISO the Real-Time Energy Inventory for each of the assets participating in the program between 7:00 a.m. and 8:00 a.m. on the Operating Day immediately following each Inventoried Energy Day. The Real-Time Energy Inventory must be reported to the ISO both in MWh and in units appropriate to the fuel type and measured in accordance with the following provisions:

(i) Oil. The Real-Time Energy Inventory of an asset that runs on oil shall be the number of dedicated barrels of oil stored in an in-service tank (located on site or at an adjacent location with direct pipeline transfer capability to the asset), excluding any amount that is unobtainable or unusable (due to priming requirements, sediment, volume below the suction line, or any other reason).

(ii) Coal. The Real-Time Energy Inventory of an asset that runs on coal shall be the number of metric tons of coal stored on site, excluding any amount that is unobtainable or unusable for any reason.

(iii) Nuclear. The Real-Time Energy Inventory of a nuclear asset shall be the number of days until the asset's next scheduled refueling outage.

(iv) Natural Gas. The Real-Time Energy Inventory for an asset that runs on natural gas shall be the amount of natural gas available to the asset pursuant to the terms of the relevant contracts submitted pursuant to Section III.K.1(a)(iii), adjusted to reflect any limitation that the suppliers listed in the contracts may have on the capability to deliver natural gas. The Market Participant must specify what portion of the asset's Real-Time Energy Inventory, in MWh, is associated with liquefied natural gas.

(v) Pumped Hydro. The Real-Time Energy Inventory of a pumped storage asset shall be the amount of water (in gallons or by elevation, consistent with the description provided by the Market Participant pursuant to Section III.K.1(b)) in the on-site reservoir that is available for generation, excluding any amount that is unobtainable or unusable for any reason.

(vi) Pondage. The Real-Time Energy Inventory of an asset with pondage shall be the amount of water (in gallons or by elevation, consistent with the description provided by the Market Participant pursuant to Section III.K.1(b)) in on-site and upstream ponds controlled by the Market Participant with a transit time to the asset of no more than 12 hours, excluding any amount that is unobtainable or unusable for any reason.

(vii) Biomass/Refuse. The Real-Time Energy Inventory of an asset that runs on biomass or refuse shall be the number of metric tons of the relevant material stored on site, excluding any amount that is unobtainable or unusable for any reason.

(viii) Electric Storage Facility. The Real-Time Energy Inventory of an Electric Storage Facility shall be its available energy in MWh.

(b) If the Market Participant fails to measure or report the energy inventory or fuel amounts for an asset as required, that asset's Real-Time Energy Inventory for the Inventoried Energy Day shall be zero.

(c) The Market Participant must limit each asset's Real-Time Energy Inventory as appropriate to respect federal and state restrictions on the use of the fuel (such as water flow or emissions limitations).

(d) The reported amounts are subject to verification by the ISO. As part of any such verification, the ISO may request additional information or documentation from a Market Participant, or may require a certificate signed by a Senior Officer of the Market Participant attesting that the reported amount of fuel is available to the Market Participant as required by the provisions of the inventoried energy program.

(e) In determining final Real-Time Energy Inventory amounts for each asset, the ISO will:

(i) adjust the reported amounts consistent with the results of any verification performed pursuant to Section III.K.3.2.1.1(d);

(ii) allocate shared fuel inventory among the relevant assets in a manner that maximizes its use based on the efficiency with which the assets convert fuel to energy (unless

information submitted pursuant to Section III.K.1(b) supports a different allocation) and that is consistent with any applicable contract provisions (in the case of natural gas) and maximum daily production limits of the assets sharing fuel inventory; and

(iii) limit each asset's Real-Time Energy Inventory to the asset's average available outage-adjusted output on the Inventoried Energy Day for a maximum duration of 72 hours.

III.K.3.2.1.2 Proration of Liquefied Natural Gas

If the total amount of Real-Time Energy Inventory associated with liquefied natural gas (excluding amounts to be supplied to an asset from a liquefied natural gas facility adjacent and directly connected to the asset) exceeds 560,000 MWh, then the ISO shall prorate such Real-Time Energy Inventory associated with liquefied natural gas as follows:

(a) any Real-Time Energy Inventory associated with liquefied natural gas that corresponds to a Market Participant's Forward LNG Inventory Election (prorated as described in Section III.K.1.1(b)) shall be counted without reduction; and

(b) any Real-Time Energy Inventory associated with liquefied natural gas that does not correspond to a Market Participant's Forward LNG Inventory Election (prorated as described in Section III.K.1.1(b)) shall be prorated such that the sum of the Real-Time Energy Inventory associated with liquefied natural gas (including the amount described in Section III.K.3.2.1.2(a)) does not exceed 560,000 MWh.

III.K.4 Cost Allocation

Costs associated with the inventoried energy program shall be allocated on a regional basis to Real-Time Load Obligation, excluding Real-Time Load Obligation associated with Storage DARDs and Real-Time Load Obligation associated with Coordinated External Transactions. Costs associated with base payments shall be allocated across all days of the months of December, January, and February; costs associated with spot payments shall be allocated to the relevant Inventoried Energy Day.

SECTION III

MARKET RULE 1

APPENDIX L

ISO NEW ENGLAND FUEL SECURITY RELIABILITY REVIEW STANDARD

As described in Section III.13.2.5.2.5A, a fuel security reliability review will be performed for certain submissions by Existing Generating Capacity Resources. This Appendix establishes the reliability trigger for that fuel security reliability review. This Appendix L will remain in effect for the 2022/23~~,~~ and 2023/24 ~~and 2024/25~~ Capacity Commitment Periods, after which this Appendix L will sunset.

The fuel security model used for reliability reviews shall consist of an hour-by-hour chronological simulation of the electric supply for the winter period from the beginning of December through the end of February. As applied to the fuel security reliability review model established pursuant to Appendix I of Planning Procedure No. 10, observation of either of the following will result in the generator being tested having its (i) Retirement De-List Bids, (ii) substitution auction demand bids, and (iii) certain bilateral transactions and reconfiguration auction demand bid offers rejected for reliability reasons:

(i) The retirement will result in the depletion of 10-minute reserves below 700 MW in any hour in the absence of a contingency in more than one liquefied natural gas supply scenario case or,

(ii) the use of load shedding in any hour pursuant to Operating Procedure No. 7.

Attachment E-2

NEPOOL Clean Tariff

I.2 Rules of Construction; Definitions

I.2.1. Rules of Construction:

In this Tariff, unless otherwise provided herein:

(a) words denoting the singular include the plural and vice versa;

(b) words denoting a gender include all genders;

(c) references to a particular part, clause, section, paragraph, article, exhibit, schedule, appendix or other attachment shall be a reference to a part, clause, section, paragraph, or article of, or an exhibit, schedule, appendix or other attachment to, this Tariff;

(d) the exhibits, schedules and appendices attached hereto are incorporated herein by reference and shall be construed with an as an integral part of this Tariff to the same extent as if they were set forth verbatim herein;

(e) a reference to any statute, regulation, proclamation, ordinance or law includes all statutes, regulations, proclamations, amendments, ordinances or laws varying, consolidating or replacing the same from time to time, and a reference to a statute includes all regulations, policies, protocols, codes, proclamations and ordinances issued or otherwise applicable under that statute unless, in any such case, otherwise expressly provided in any such statute or in this Tariff;

(f) a reference to a particular section, paragraph or other part of a particular statute shall be deemed to be a reference to any other section, paragraph or other part substituted therefor from time to time;

(g) a definition of or reference to any document, instrument or agreement includes any amendment or supplement to, or restatement, replacement, modification or novation of, any such document, instrument or agreement unless otherwise specified in such definition or in the context in which such reference is used;

(h) a reference to any person (as hereinafter defined) includes such person's successors and permitted assigns in that designated capacity;

(i) any reference to "days" shall mean calendar days unless "Business Days" (as hereinafter defined) are expressly specified;

(j) if the date as of which any right, option or election is exercisable, or the date upon which any amount is due and payable, is stated to be on a date or day that is not a Business Day, such right, option or election may be exercised, and such amount shall be deemed due and payable, on the next succeeding Business Day with the same effect as if the same was exercised or made on such date or day (without, in the case of any such payment, the payment or accrual of any interest or

other late payment or charge, provided such payment is made on such next succeeding Business Day);

(k) words such as "hereunder," "hereto," "hereof" and "herein" and other words of similar import shall, unless the context requires otherwise, refer to this Tariff as a whole and not to any particular article, section, subsection, paragraph or clause hereof; and a reference to "include" or "including" means including without limiting the generality of any description preceding such term, and for purposes hereof the rule of *ejusdem generis* shall not be applicable to limit a general statement, followed by or referable to an enumeration of specific matters, to matters similar to those specifically mentioned.

I.2.2. Definitions:

In this Tariff, the terms listed in this section shall be defined as described below:

Active Demand Capacity Resource is one or more Demand Response Resources located within the same Dispatch Zone, that is registered with the ISO, assigned a unique resource identification number by the ISO, and participates in the Forward Capacity Market to fulfill a Market Participant's Capacity Supply Obligation pursuant to Section III.13 of Market Rule 1.

Actual Capacity Provided is the measure of capacity provided during a Capacity Scarcity Condition, as described in Section III.13.7.2.2 of Market Rule 1.

Actual Load is the consumption at the Retail Delivery Point for the hour.

Additional Resource Blackstart O&M Payment is defined and calculated as specified in Section 5.1.2 of Schedule 16 to the OATT.

Additional Resource Specified-Term Blackstart Capital Payment is defined and calculated as specified in Section 5.1.2 of Schedule 16 to the OATT.

Additional Resource Standard Blackstart Capital Payment is defined and calculated as specified in Section 5.1.2 of Schedule 16 to the OATT.

Administrative Costs are those costs incurred in connection with the review of Applications for transmission service and the carrying out of System Impact Studies and Facilities Studies.

Administrative Export De-List Bid is a bid that may be submitted in a Forward Capacity Auction by certain Existing Generating Capacity Resources subject to a multi-year contract to sell capacity outside of the New England Control Area during the associated Capacity Commitment Period, as described in Section III.13.1.2.3.1.4 of Market Rule 1.

Administrative Sanctions are defined in Section III.B.4.1.2 of Appendix B of Market Rule 1.

ADR Neutrals are one or more firms or individuals identified by the ISO with the advice and consent of the Participants Committee that are prepared to act as neutrals in ADR proceedings under Appendix D to Market Rule 1.

Advance is defined in Section IV.A.3.2 of the Tariff.

Affected Party, for purposes of the ISO New England Billing Policy, is defined in Section 6.3.5 of the ISO New England Billing Policy.

Affiliate is any person or entity that controls, is controlled by, or is under common control by another person or entity. For purposes of this definition, "control" means the possession, directly or indirectly, of the authority to direct the management or policies of an entity. A voting interest of ten percent or more shall create a rebuttable presumption of control.

AGC is automatic generation control.

AGC SetPoint is the desired output signal for a Resource providing Regulation that is produced by the AGC system as frequently as every four seconds.

AGC SetPoint Deadband is a deadband expressed in megawatts that is applied to changing values of the AGC SetPoint for generating units.

Allocated Assessment is a Covered Entity’s right to seek and obtain payment and recovery of its share in any shortfall payments under Section 3.3 or Section 3.4 of the ISO New England Billing Policy.

Alternative Dispute Resolution (ADR) is the procedure set forth in Appendix D to Market Rule 1.

Alternative Technology Regulation Resource (ATRR) is one or more facilities capable of providing Regulation that have been registered in accordance with the Asset Registration Process. An Alternative Technology Regulation Resource is eligible to participate in the Regulation Market.

Ancillary Services are those services that are necessary to support the transmission of electric capacity and energy from resources to loads while maintaining reliable operation of the New England Transmission System in accordance with Good Utility Practice.

Announced Schedule 1 EA Amount, Announced Schedule 2 EA Amount, Announced Schedule 3 EA Amount are defined in Section IV.B.2.2 of the Tariff.

Annual Transmission Revenue Requirements are the annual revenue requirements of a PTO's PTF or of all PTOs' PTF for purposes of the OATT shall be the amount determined in accordance with Attachment F to the OATT.

Annual Reconfiguration Transaction is a bilateral transaction that may be used in accordance with Section III.13.5.4 of Market Rule 1 to specify a price when a Capacity Supply Obligation is transferred using supply offers and demand bids in Annual Reconfiguration Auctions.

Applicants, for the purposes of the ISO New England Financial Assurance Policy, are entities applying for Market Participant status or for transmission service from the ISO.

Application is a written request by an Eligible Customer for transmission service pursuant to the provisions of the OATT.

Asset is a Generator Asset, a Demand Response Asset, a component of an On-Peak Demand Resource or Seasonal Peak Demand Resource, a Load Asset (including an Asset Related Demand), an Alternative Technology Regulation Resource, or a Tie-Line Asset.

Asset Registration Process is the ISO business process for registering an Asset.

Asset Related Demand is a Load Asset that has been discretely modeled within the ISO's dispatch and settlement systems, settles at a Node, has been registered in accordance with the Asset Registration

Process, and is made up of either: (1) one or more individual end-use metered customers receiving service from the same point or points of electrical supply with an aggregate average hourly load of 1 MW or greater during the 12 months preceding its registration; (2) a Storage DARD with a consumption capability of at least 0.1 MW; or (3) one or more storage facilities that are not Electric Storage Facilities with an aggregate consumption capability of at least 1 MW.

Asset Related Demand Bid Block-Hours are Block-Hours assigned to the Lead Market Participant for each Asset Related Demand bid. Blocks of the bid in effect for each hour will be totaled to determine the daily quantity of Asset Related Demand Bid Block-Hours. In the case that a Resource has a Real-Time unit status of "unavailable" for an entire day, that day will not contribute to the quantity of Asset Related Demand Bid Block-Hours. However, if the Resource has at least one hour of the day with a unit status of "available," the entire day will contribute to the quantity of Asset Related Demand Bid Block-Hours.

Asset-Specific Going Forward Costs are the net costs of an asset that is part of an Existing Generating Capacity Resource, calculated for the asset in the same manner as the net costs of Existing Generating Capacity Resources as described in Section III.13.1.2.3.2.1.1.1 (for an asset with a Static De-List Bid or an Export Bid) or Section III.13.1.2.3.2.1.1.2 (for an asset with a Permanent De-List Bid or Retirement De-List Bid).

Assigned Meter Reader reports to the ISO the hourly and monthly MWh associated with the Asset. These MWh are used for settlement. The Assigned Meter Reader may designate an agent to help fulfill its Assigned Meter Reader responsibilities; however, the Assigned Meter Reader remains functionally responsible to the ISO.

Auction Revenue Right (ARR) is a right to receive FTR Auction Revenues in accordance with Appendix C of Market Rule 1.

Auction Revenue Right Allocation (ARR Allocation) is defined in Section 1 of Appendix C of Market Rule 1.

Auction Revenue Right Holder (ARR Holder) is an entity which is the record holder of an Auction Revenue Right (excluding an Incremental ARR) in the register maintained by the ISO.

Authorized Commission is defined in Section 3.3 of the ISO New England Information Policy.

Authorized Person is defined in Section 3.3 of the ISO New England Information Policy.

Automatic Response Rate is the response rate, in MW/Minute, at which a Market Participant is willing to have a Regulation Resource change its output or consumption while providing Regulation between the Regulation High Limit and Regulation Low Limit.

Available Energy is a value that reflects the MWhs of energy available from an Electric Storage Facility for economic dispatch.

Available Storage is a value that reflects the MWhs of unused storage available from an Electric Storage Facility for economic dispatch of consumption.

Average Hourly Load Reduction is either: (i) the sum of the On-Peak Demand Resource's electrical energy reduction during Demand Resource On-Peak Hours in the month divided by the number of Demand Resource On-Peak Hours in the month; or (ii) the sum of the Seasonal Peak Demand Resource's electrical energy reduction during Demand Resource Seasonal Peak Hours in the month divided by the number of Demand Resource Seasonal Peak Hours in the month. The On-Peak Demand Resource's or Seasonal Peak Demand Resource's electrical energy reduction and Average Hourly Load Reduction shall be determined consistent with the resource's Measurement and Verification Plan, which shall be reviewed by the ISO to ensure consistency with the measurement and verification requirements, as described in Section III.13.1.4.3 of Market Rule 1 and the ISO New England Manuals.

Average Hourly Output is either: (i) the sum of the On-Peak Demand Resource's electrical energy output during Demand Resource On-Peak Hours in the month divided by the number of Demand Resource On-Peak Hours in the month; or (ii) the sum of the Seasonal Peak Demand Resource's electrical energy output during Demand Resource Seasonal Peak Hours in the month divided by the number of Demand Resource Seasonal Peak Hours in the month. Electrical energy output and Average Hourly Output shall be determined consistent with the resource's Measurement and Verification Plan, which shall be reviewed by the ISO to ensure consistency with the measurement and verification requirements, as described in Section III.13.1.4.3 of Market Rule 1 and the ISO New England Manuals.

Average Monthly PER is calculated in accordance with Section III.13.7.1.2.2 of Market Rule 1.

Backstop Transmission Solution is a solution proposed: (i) to address a reliability or market efficiency need identified by the ISO in a Needs Assessment reported by the ISO pursuant to Section 4.1(i) of Attachment K to the ISO OATT, (ii) by the PTO or PTOs with an obligation under Schedule 3.09(a) of the TOA to address the identified need; and (iii) in circumstances in which the competitive solution process specified in Section 4.3 of Attachment K to the ISO OATT will be utilized.

Bankruptcy Code is the United States Bankruptcy Code.

Bankruptcy Event occurs when a Covered Entity files a voluntary or involuntary petition in bankruptcy or commences a proceeding under the United States Bankruptcy Code or any other applicable law concerning insolvency, reorganization or bankruptcy by or against such Covered Entity as debtor.

Bilateral Contract (BC) is any of the following types of contracts: Internal Bilateral for Load, Internal Bilateral for Market for Energy, and External Transactions.

Bilateral Contract Block-Hours are Block-Hours assigned to the seller and purchaser of an Internal Bilateral for Load, Internal Bilateral for Market for Energy and External Transactions; provided, however, that only those contracts which apply to the Real-Time Energy Market will accrue Block-Hours.

Binary Storage DARD is a DARD that participates in the New England Markets as part of a Binary Storage Facility, as described in Section III.1.10.6 of Market Rule 1.

Binary Storage Facility is a type of Electric Storage Facility, as described in Section III.1.10.6 of Market Rule 1.

Blackstart Capability Test is the test, required by ISO New England Operating Documents, of a resource's capability to provide Blackstart Service.

Blackstart Capital Payment is the annual compensation, as calculated pursuant to Section 5.1, or as referred to in Section 5.2, of Schedule 16 to the OATT, for a Designated Blackstart Resource's Blackstart Equipment capital costs associated with the provision of Blackstart Service (excluding the capital costs associated with compliance with NERC Critical Infrastructure Protection Reliability Standards as part of Blackstart Service).

Blackstart Equipment is any equipment that is solely necessary to enable the Designated Blackstart Resource to provide Blackstart Service and is not required to provide other products or services under the Tariff.

Blackstart O&M Payment is the annual Blackstart O&M compensation calculated under either Section 5.1 or 5.2 of Schedule 16 of the OATT, as applicable.

Blackstart Owner is the Market Participant who is authorized on behalf of the Generator Owner(s) to offer or operate the resource as a Designated Blackstart Resource and is authorized to commit the resource to provide Blackstart Service.

Blackstart Service is the Ancillary Service described in Section II.47 of the Tariff and Schedule 16 of the OATT.

Blackstart Service Commitment is the commitment by a Blackstart Owner for its resource to provide Blackstart Service and the acceptance of that commitment by the ISO, in the manner detailed in ISO New England Operating Procedure No. 11 – Designated Blackstart Resource Administration (OP 11), and which includes a commitment to provide Blackstart Service established under Operating Procedure 11 – Designated Blackstart Resource Administration (OP11).

Blackstart Service Minimum Criteria are the minimum criteria that a Blackstart Owner and its resource must meet in order to establish and maintain a resource as a Designated Blackstart Resource.

Blackstart Standard Rate Payment is the formulaic rate of monthly compensation, as calculated pursuant to Section 5 of Schedule 16 to the OATT, paid to a Blackstart Owner for the provision of Blackstart Service from a Designated Blackstart Resource.

Blackstart Station is comprised of (i) a single Designated Blackstart Resource or (ii) two or more Designated Blackstart Resources that share Blackstart Equipment.

Blackstart Station-specific Rate Payment is the Commission-approved compensation, as calculated pursuant to Section 5.2 of Schedule 16 to the OATT, paid to a Blackstart Owner on a monthly basis for the provision of Blackstart Service by Designated Blackstart Resources located at a specific Blackstart Station.

Blackstart Station-specific Rate Capital Payment is a component of the Blackstart Station-specific Rate Payment that reflects a Blackstart Station's capital Blackstart Equipment costs associated with the provision of Blackstart Service (excluding the capital costs associated with compliance with NERC Critical Infrastructure Protection Reliability Standards as part of Blackstart Service).

Block is defined as follows: (1) With respect to Bilateral Contracts, a Bilateral Contract administered by the ISO for an hour; (2) with respect to Supply Offers administered by the ISO, a quantity with a related price for Energy (Supply Offers for Energy may contain multiple sets of quantity and price pairs for each hour); (3) with respect to Demand Bids administered by the ISO, a quantity with a related price for Energy (Demand Bids for Energy may contain multiple sets of quantity and price pairs for each hour); (4) with respect to Increment Offers administered by the ISO, a quantity with a related price for Energy (Increment Offers for Energy may contain multiple sets of quantity and price pairs for each hour); (5) with respect to Decrement Bids administered by the ISO, a quantity with a related price for Energy (Decrement Bids for Energy may contain multiple sets of quantity and price pairs for each hour); (6) with respect to Asset Related Demand bids administered by the ISO, a quantity with a related price for Energy (Asset Related Demand bids may contain multiple sets of quantity and price pairs for each hour); and (7) with respect to Demand Reduction Offers administered by the ISO, a quantity of reduced demand with a related price (Demand Reduction Offers may contain multiple sets of quantity and price pairs for the day).

Block-Hours are the number of Blocks administered for a particular hour.

Budget and Finance Subcommittee is a subcommittee of the Participants Committee, the responsibilities of which are specified in Section 8.4 of the Participants Agreement.

Business Day is any day other than a Saturday or Sunday or ISO holidays as posted by the ISO on its website.

Cancelled Start NCPC Credit is an NCPC Credit calculated pursuant to Appendix F to Market Rule 1.

Capability Demonstration Year is the one year period from September 1 through August 31.

Capacity Acquiring Resource is a resource that is seeking to acquire a Capacity Supply Obligation through: (1) a Capacity Supply Obligation Bilateral, as described in Section III.13.5.1, or; (2) an annual or monthly reconfiguration auction, as described in Section III.13.4.

Capacity Balancing Ratio is a ratio used in calculating the Capacity Performance Payment in the Forward Capacity Market, as described in Section III.13.7.2.3 of Market Rule 1.

Capacity Base Payment is the portion of revenue received in the Forward Capacity Market as described in Section III.13.7.1 of Market Rule 1.

Capacity Capability Interconnection Standard has the meaning specified in Schedule 22, Schedule 23, and Schedule 25 of the OATT.

Capacity Clearing Price is the clearing price for a Capacity Zone for a Capacity Commitment Period resulting from the Forward Capacity Auction conducted for that Capacity Commitment Period, as determined in accordance with Section III.13.2.7 of Market Rule 1.

Capacity Commitment Period is the one-year period from June 1 through May 31 for which obligations are assumed and payments are made in the Forward Capacity Market.

Capacity Cost (CC) is one of four forms of compensation that may be paid to resources providing VAR Service under Schedule 2 of the OATT.

Capacity Export Through Import Constrained Zone Transaction is defined in Section III.1.10.7(f)(i) of Market Rule 1.

Capacity Load Obligation is the quantity of capacity for which a Market Participant is financially responsible as described in Section III.13.7.5.2 of Market Rule 1.

Capacity Load Obligation Acquiring Participant is a load serving entity or any other Market Participant seeking to acquire a Capacity Load Obligation through a Capacity Load Obligation Bilateral, as described in Section III.13.5.2 of Market Rule 1.

Capacity Network Import Capability (CNI Capability) is as defined in Section I of Schedule 25 of the OATT.

Capacity Network Import Interconnection Service (CNI Interconnection Service) is as defined in Section I of Schedule 25 of the OATT.

Capacity Load Obligation Bilateral is a bilateral contract through which a Market Participant may transfer all or a portion of its Capacity Load Obligation to another entity, as described in Section III.13.5 of Market Rule 1.

Capacity Load Obligation Transferring Participant is an entity that has a Capacity Load Obligation and is seeking to shed such obligation through a Capacity Load Obligation Bilateral, as described in Section III.13.5.2 of Market Rule 1.

Capacity Network Resource (CNR) is defined in Section I of Schedule 22 and Attachment 1 to Schedule 23 of the OATT.

Capacity Network Resource Interconnection Service (CNR Interconnection Service) is defined in Section I of Schedule 22 and Attachment 1 to Schedule 23 of the OATT.

Capacity Performance Bilateral is a transaction for transferring Capacity Performance Score, as described in Section III.13.5.3 of Market Rule 1.

Capacity Performance Payment is the performance-dependent portion of revenue received in the Forward Capacity Market, as described in Section III.13.7.2 of Market Rule 1.

Capacity Performance Payment Rate is a rate used in calculating Capacity Performance Payments, as described in Section III.13.7.2.5 of Market Rule 1.

Capacity Performance Score is a figure used in determining Capacity Performance Payments, as described in Section III.13.7.2.4 of Market Rule 1.

Capacity Rationing Rule addresses whether offers and bids in a Forward Capacity Auction may be rationed, as described in Section III.13.2.6 of Market Rule 1.

Capacity Scarcity Condition is a period during which performance is measured in the Forward Capacity Market, as described in Section III.13.7.2.1 of Market Rule 1.

Capacity Scarcity Condition is a period during which performance is measured in the Forward Capacity Market, as described in Section III.13.7.2.1 of Market Rule 1.

Capacity Supply Obligation is an obligation to provide capacity from a resource, or a portion thereof, to satisfy a portion of the Installed Capacity Requirement that is acquired through a Forward Capacity Auction in accordance with Section III.13.2, a reconfiguration auction in accordance with Section III.13.4, or a Capacity Supply Obligation Bilateral in accordance with Section III.13.5.1 of Market Rule 1.

Capacity Supply Obligation Bilateral is a bilateral contract through which a Market Participant may transfer all or a part of its Capacity Supply Obligation to another entity, as described in Section III.13.5.1 of Market Rule 1.

Capacity Transfer Rights (CTRs) are calculated in accordance with Section III.13.7.5.4.

Capacity Transferring Resource is a resource that has a Capacity Supply Obligation and is seeking to shed such obligation, or a portion thereof, through: (1) a Capacity Supply Obligation Bilateral, as described in Section III.13.5.1, or; (2) an annual or monthly reconfiguration auction, as described in Section III.13.4.

Capacity Zone is a geographic sub-region of the New England Control Area as determined in accordance with Section III.12.4 of Market Rule 1.

Capacity Zone Demand Curves are the demand curves used in the Forward Capacity Market for a Capacity Zone as specified in Sections III.13.2.2.2 and III.13.2.2.3.

Capital Funding Charge (CFC) is defined in Section IV.B.2 of the Tariff.

CARL Data is Control Area reliability data submitted to the ISO to permit an assessment of the ability of an external Control Area to provide energy to the New England Control Area in support of capacity offered to the New England Control Area by that external Control Area.

Category B Designated Blackstart Resource has the same meaning as Designated Blackstart Resource.

Charge is a sum of money due from a Covered Entity to the ISO, either in its individual capacity or as billing and collection agent for NEPOOL pursuant to the Participants Agreement.

CLAIM10 is the value, expressed in megawatts, calculated pursuant to Section III.9.5.3 of the Tariff.

CLAIM30 is the value, expressed in megawatts, calculated pursuant to Section III.9.5.3 of the Tariff.

Claimed Capability Audit is performed to determine the real power output capability of a Generator Asset or the demand reduction capability of a Demand Response Resource.

Cluster Enabling Transmission Upgrade (CETU) has the meaning specified in Section I of Schedule 22, Attachment 1 to Schedule 23, and Section I of Schedule 25 of the OATT.

Cluster Enabling Transmission Upgrade Regional Planning Study (CRPS) has the meaning specified in Section I of Schedule 22, Attachment 1 to Schedule 23, and Section I of Schedule 25 of the OATT.

Cluster Entry Deadline has the meaning specified in Section I of Schedule 22, Attachment 1 to Schedule 23, and Section I of Schedule 25 of the OATT.

Cluster Interconnection System Impact Study (CSIS) has the meaning specified in Section I of Schedule 22, Attachment 1 to Schedule 23, and Section I of Schedule 25 of the OATT.

Clustering has the meaning specified in Section I of Schedule 22, Attachment 1 to Schedule 23, and Section I of Schedule 25 of the OATT.

CNR Capability is defined in Section I of Schedule 22 and Attachment 1 to Schedule 23 of the OATT.

Coincident Peak Contribution is a Market Participant's share of the New England Control Area coincident peak demand for the prior calendar year as determined prior to the start of each Capacity Commitment Period, which reflects the sum of the prior year's annual coincident peak contributions of the customers served by the Market Participant at each Load Asset. Daily Coincident Peak Contribution

values shall be submitted by the Assigned Meter Reader or Host Participant by the meter reading deadline to the ISO.

Commercial Capacity is capacity that has achieved FCM Commercial Operation.

Commission is the Federal Energy Regulatory Commission.

Commitment Period is (i) for a Day-Ahead Energy Market commitment, a period of one or more contiguous hours for which a Resource is cleared in the Day-Ahead Energy Market, and (ii) for a Real-Time Energy Market commitment, the period of time for which the ISO indicates the Resource is being committed when it issues the Dispatch Instruction. If the ISO does not indicate the period of time for which the Resource is being committed in the Real-Time Energy Market, then the Commitment Period is the Minimum Run Time for an offline Resource and one hour for an online Resource.

Common Costs are those costs associated with a Station that are avoided only by the clearing of the Static De-List Bids, the Permanent De-List Bids, or the Retirement De-List Bids of all the Existing Generating Capacity Resources comprising the Station.

Completed Application is an Application that satisfies all of the information and other requirements of the OATT, including any required deposit.

Compliance Effective Date is the date upon which the changes in the predecessor NEPOOL Open Access Transmission Tariff which have been reflected herein to comply with the Commission's Order of April 20, 1998 became effective.

Composite FCM Transaction is a transaction for separate resources seeking to participate as a single composite resource in a Forward Capacity Auction in which multiple Designated FCM Participants provide capacity, as described in Section III.13.1.5 of Market Rule 1.

Conditional Qualified New Resource is defined in Section III.13.1.1.2.3(f) of Market Rule 1.

Confidential Information is defined in Section 2.1 of the ISO New England Information Policy, which is Attachment D to the Tariff.

Confidentiality Agreement is Attachment 1 to the ISO New England Billing Policy.

Congestion is a condition of the New England Transmission System in which transmission limitations prevent unconstrained regional economic dispatch of the power system. Congestion is the condition that results in the Congestion Component of the Locational Marginal Price at one Location being different from the Congestion Component of the Locational Marginal Price at another Location during any given hour of the dispatch day in the Day-Ahead Energy Market or Real-Time Energy Market.

Congestion Component is the component of the nodal price that reflects the marginal cost of congestion at a given Node or External Node relative to the reference point. When used in connection with Zonal Price and Hub Price, the term Congestion Component refers to the Congestion Components of the nodal prices that comprise the Zonal Price and Hub Price weighted and averaged in the same way that nodal prices are weighted to determine Zonal Price and averaged to determine the Hub Price.

Congestion Cost is the cost of congestion as measured by the difference between the Congestion Components of the Locational Marginal Prices at different Locations and/or Reliability Regions on the New England Transmission System.

Congestion Paying LSE is, for the purpose of the allocation of FTR Auction Revenues to ARR Holders as provided for in Appendix C of Market Rule 1, a Market Participant or Non-Market Participant Transmission Customer that is responsible for paying for Congestion Costs as a Transmission Customer paying for Regional Network Service under the Transmission, Markets and Services Tariff, unless such Transmission Customer has transferred its obligation to supply load in accordance with ISO New England System Rules, in which case the Congestion Paying LSE shall be the Market Participant supplying the transferred load obligation. The term Congestion Paying LSE shall be deemed to include, but not be limited to, the seller of internal bilateral transactions that transfer Real-Time Load Obligations under the ISO New England System Rules.

Congestion Revenue Fund is the amount available for payment of target allocations to FTR Holders from the collection of Congestion Cost.

Congestion Shortfall means congestion payments exceed congestion charges during the billing process in any billing period.

Contingency Reserve has the meaning specified in the Glossary of Terms Used in NERC Reliability Standards.

Contingency Reserve Restoration Period has the meaning specified in the Glossary of Terms Used in NERC Reliability Standards.

Continuous Storage ATRR is an ATRR that participates in the New England Markets as part of a Continuous Storage Facility, as described in Section III.1.10.6 of Market Rule 1.

Continuous Storage DARD is a DARD that participates in the New England Markets as part of a Continuous Storage Facility, as described in Section III.1.10.6 of Market Rule 1.

Continuous Storage Generator Asset is a Generator Asset that participates in the New England Markets as part of a Continuous Storage Facility, as described in Section III.1.10.6 of Market Rule 1.

Continuous Storage Facility is a type of Electric Storage Facility, as described in Section III.1.10.6 of Market Rule 1.

Control Agreement is the document posted on the ISO website that is required if a Market Participant's cash collateral is to be invested in BlackRock funds.

Control Area is an electric power system or combination of electric power systems to which a common automatic generation control scheme is applied in order to:

(1) match, at all times, the power output of the generators within the electric power system(s) and capacity and energy purchased from entities outside the electric power system(s), with the load within the electric power system(s);
(2) maintain scheduled interchange with other Control Areas, within the limits of Good Utility Practice;
(3) maintain the frequency of the electric power system(s) within reasonable limits in accordance with Good Utility Practice and the criteria of the applicable regional reliability council or the North American Electric Reliability Corporation; and
(4) provide sufficient generating capacity to maintain operating reserves in accordance with Good Utility Practice.

Controllable Behind-the-Meter Generation means generation whose output can be controlled located at the same facility as a DARD or a Demand Response Asset, excluding: (1) generators whose output is separately metered and reported and (2) generators that cannot operate electrically synchronized to, and that are operated only when the facility loses its supply of power from, the New England Transmission System, or when undergoing related testing.

Coordinated External Transaction is an External Transaction at an external interface for which the enhanced scheduling procedures in Section III.1.10.7.A are implemented. A transaction to wheel energy into, out of or through the New England Control Area is not a Coordinated External Transaction.
Coordinated Transaction Scheduling means the enhanced scheduling procedures set forth in Section III.1.10.7.A.

Correction Limit means the date that is one hundred and one (101) calendar days from the last Operating Day of the month to which the data applied. As described in Section III.3.6.1 of Market Rule 1, this will be the period during which meter data corrections must be submitted unless they qualify for submission as a Requested Billing Adjustment under Section III.3.7 of Market Rule 1.

Cost of Energy Consumed (CEC) is one of four forms of compensation that may be paid to resources providing VAR Service under Schedule 2 of the OATT.

Cost of Energy Produced (CEP) is one of four forms of compensation that may be paid to resources providing VAR Service under Schedule 2 of the OATT.

Cost of New Entry (CONE) is the estimated cost of new entry ($/kW-month) for a capacity resource that is determined by the ISO for each Forward Capacity Auction pursuant to Section III.13.2.4.

Counterparty means the status in which the ISO acts as the contracting party, in its name and own right and not as an agent, to an agreement or transaction with a Customer (including assignments involving Customers) involving sale to the ISO, and/or purchase from the ISO, of Regional Transmission Service and market and other products and services, and other transactions and assignments involving Customers, all as described in the Tariff.

Covered Entity is defined in the ISO New England Billing Policy.

Credit Coverage is third-party credit protection obtained by the ISO, in the form of credit insurance coverage, a performance or surety bond, or a combination thereof.

Credit Qualifying means a Rated Market Participant that has an Investment Grade Rating and an Unrated Market Participant that satisfies the Credit Threshold.

Credit Threshold consists of the conditions for Unrated Market Participants outlined in Section II.B.2 of the ISO New England Financial Assurance Policy.

Critical Energy Infrastructure Information (CEII) is defined in Section 3.0(j) of the ISO New England Information Policy, which is Attachment D to the Tariff.

Current Ratio is, on any date, all of a Market Participant's or Non-Market Participant Transmission Customer's current assets divided by all of its current liabilities, in each case as shown on the most recent financial statements provided by such Market Participant or Non-Market Participant Transmission Customer to the ISO.

Curtailment is a reduction in the dispatch of a transaction that was scheduled, using transmission service, in response to a transfer capability shortage as a result of system reliability conditions.

Customer is a Market Participant, a Transmission Customer or another customer of the ISO.

Data Reconciliation Process means the process by which meter reconciliation and data corrections that are discovered by Governance Participants after the Invoice has been issued for a particular month or that are discovered prior to the issuance of the Invoice for the relevant month but not included in that Invoice or in the other Invoices for that month and are reconciled by the ISO on an hourly basis based on data submitted to the ISO by the Host Participant Assigned Meter Reader or Assigned Meter Reader.

Day-Ahead is the calendar day immediately preceding the Operating Day.

Day-Ahead Adjusted Load Obligation is defined in Section III.3.2.1(a)(1) of Market Rule 1.

Day-Ahead Ancillary Services means Day-Ahead Generation Contingency Reserve, Day-Ahead Replacement Energy Reserve, and Day-Ahead Energy Imbalance Reserve.

Day-Ahead Congestion Revenue is defined in Section III.3.2.1(i) of Market Rule 1.

Day-Ahead Demand Reduction Obligation is defined in Section III.3.2.1(a)(1) of Market Rule 1.

Day-Ahead Energy Imbalance Reserve is a form of reserve capability that is procured in the Day-Ahead Energy Market to help satisfy the Forecast Energy Requirement Demand Quantity described in Section III.1.8.6 of Market Rule 1.

Day-Ahead Energy Imbalance Reserve Demand Quantity is described in Section III.1.8.5(f) of Market Rule 1.

Day-Ahead Energy Imbalance Reserve Obligation is defined in Section III.3.2.1(a)(2) of Market Rule 1.

Day-Ahead Energy Market means: (i) prior to June 1, 2024, the schedule of commitments for the purchase or sale of energy, purchase of demand reductions, payment of Congestion Costs, and payment for losses developed by the ISO as a result of the offers and specifications submitted in accordance with Section III.1.10 of Market Rule 1, and (ii) commencing on June 1, 2024, the schedule of commitments for the purchase or sale of energy, the sale of ancillary services, purchase of demand reductions, payment of Congestion Costs, and payment for losses developed by the ISO as a result of the offers and specifications submitted in accordance with Sections III.1.8 and III.1.10 of Market Rule 1.

Day-Ahead Energy Market Congestion Charge/Credit is defined in Section III.3.2.1(f) of Market Rule 1.

Day-Ahead Energy Market Energy Charge/Credit is defined in Section III.3.2.1(f) of Market Rule 1.

Day-Ahead Energy Market Loss Charge/Credit is defined in Section III.3.2.1(f) of Market Rule 1.

Day-Ahead Energy Market NCPC Credit is an NCPC Credit calculated pursuant to Appendix F to Market Rule 1.

Day-Ahead External Transaction Export and Decrement Bid NCPC Credit is an NCPC Credit calculated pursuant to Appendix F to Market Rule 1.

Day-Ahead External Transaction Import and Increment Offer NCPC Credit is an NCPC Credit calculated pursuant to Appendix F to Market Rule 1.

Day-Ahead Four-Hour Reserve is a form of reserve capability that is procured in the Day-Ahead Energy Market based on the system-wide requirements described in Section III.1.8.5 of Market Rule 1.

Day-Ahead Four-Hour Reserve Obligation is defined in Section III.3.2.1(a)(2) of Market Rule 1.

Day-Ahead Generation Contingency Reserve means Day-Ahead Ten-Minute Spinning Reserve, Day-Ahead Ten-Minute Non-Spinning Reserve, and Day-Ahead Thirty-Minute Operating Reserve.

Day-Ahead Generation Obligation is defined in Section III.3.2.1(a)(1) of Market Rule 1.

Day-Ahead Load Obligation is defined in Section III.3.2.1(a)(1) of Market Rule 1.

Day-Ahead Locational Adjusted Net Interchange is defined in Section III.3.2.1(a)(1) of Market Rule 1.

Day-Ahead Loss Charges or Credits is defined in Section III.3.2.1(k) of Market Rule 1.

Day-Ahead Loss Revenue is defined in Section III.3.2.1(j) of Market Rule 1.

Day-Ahead Ninety-Minute Reserve is a form of reserve capability that is procured in the Day-Ahead Energy Market based on the system-wide requirements described in Section III.1.8.5 of Market Rule 1.

Day-Ahead Ninety-Minute Reserve Obligation is defined in Section III.3.2.1(a)(2) of Market Rule 1.

Day-Ahead Prices means the Locational Marginal Prices resulting from the Day-Ahead Energy Market, and commencing on June 1, 2024, the additional prices resulting from the Day-Ahead Energy Market described in Section III.2.6.2 of Market Rule 1.

Day-Ahead Replacement Energy Reserve means Day-Ahead Ninety-Minute Reserve and Day-Ahead Four-Hour Reserve.

Day-Ahead Ten-Minute Non-Spinning Reserve is a form of ten-minute reserve capability that is procured in the Day-Ahead Energy Market based on the system-wide requirements described in Section III.1.8.5 of Market Rule 1.

Day-Ahead Ten-Minute Non-Spinning Reserve Obligation is defined in Section III.3.2.1(a)(2) of Market Rule 1.

Day-Ahead Ten-Minute Spinning Reserve is a form of ten-minute reserve capability that is procured in the Day-Ahead Energy Market based on the system-wide requirements described in Section III.1.8.5 of Market Rule 1.

Day-Ahead Ten-Minute Spinning Reserve Demand Quantity is described in Section III.1.8.5(a) of Market Rule 1.

Day-Ahead Ten-Minute Spinning Reserve Obligation is defined in Section III.3.2.1(a)(2) of Market Rule 1.

Day-Ahead Thirty-Minute Operating Reserve is a form of reserve capability that is procured in the Day-Ahead Energy Market based on the system-wide requirements described in Section III.1.8.5 of Market Rule 1.

Day-Ahead Thirty-Minute Operating Reserve Obligation is defined in Section III.3.2.1(a)(2) of Market Rule 1.

Day-Ahead Total Four-Hour Reserve Demand Quantity is described in Section III.1.8.5(e) of Market Rule 1.

Day-Ahead Total Ninety-Minute Reserve Demand Quantity is described in Section III.1.8.5(d) of Market Rule 1.

Day-Ahead Total Ten-Minute Reserve Demand Quantity is described in Section III.1.8.5(b) of Market Rule 1.

Day-Ahead Total Thirty-Minute Operating Reserve Demand Quantity is described in Section III.1.8.5(c) of Market Rule 1.

DDP Dispatchable Resource is any Dispatchable Resource that the ISO dispatches using Desired Dispatch Points in the Resource's Dispatch Instructions.

Debt-to-Total Capitalization Ratio is, on any date, a Market Participant's or Non-Market Participant Transmission Customer's total debt (including all current borrowings) divided by its total shareholders' equity plus total debt, in each case as shown on the most recent financial statements provided by such Market Participant or Non-Market Participant Transmission Customer to the ISO.

Decrement Bid means a bid to purchase energy at a specified Location in the Day-Ahead Energy Market which is not associated with a physical load. An accepted Decrement Bid results in scheduled load at the specified Location in the Day-Ahead Energy Market.

Default Amount is all or any part of any amount due to be paid by any Covered Entity that the ISO, in its reasonable opinion, believes will not or has not been paid when due (other than in the case of a payment dispute for any amount due for transmission service under the OATT).

Default Period is defined in Section 3.3.h(i) of the ISO New England Billing Policy.

Delivering Party is the entity supplying capacity and/or energy to be transmitted at Point(s) of Receipt under the OATT.

Demand Bid means a request to purchase an amount of energy, at a specified Location, or an amount of energy at a specified price, that is associated with a physical load. A cleared Demand Bid in the Day-Ahead Energy Market results in scheduled load at the specified Location. Demand Bids submitted for use in the Real-Time Energy Market are specific to Dispatchable Asset Related Demands only.

Demand Bid Block-Hours are the Block-Hours assigned to the submitting Customer for each Demand Bid.

Demand Bid Cap is $2,000/MWh.

Demand Capacity Resource means an Existing Demand Capacity Resource or a New Demand Capacity Resource. There are three Demand Capacity Resource types: Active Demand Capacity Resources, On-Peak Demand Resources, and Seasonal Peak Demand Resources.

Demand Designated Entity is the entity designated by a Market Participant to receive Dispatch Instructions for Demand Response Resources in accordance with the provisions set forth in ISO New England Operating Procedure No. 14.

Demand Reduction Offer is an offer by a Market Participant with a Demand Response Resource to reduce demand.

Demand Reduction Offer Block-Hours are Block-Hours assigned to the Lead Market Participant for each Demand Reduction Offer. Blocks of the Demand Reduction Offer in effect for each hour will be totaled to determine the quantity of Demand Reduction Offer Block-Hours for a given day. In the case that a Resource has a Real-Time unit status of “unavailable” for the entire day, that day will not contribute to the quantity of Demand Reduction Offer Block-Hours. However, if the Resource has at least one hour of the day with a unit status of “available,” the entire day will contribute to the quantity of Demand Reduction Offer Block-Hours.

Demand Reduction Threshold Price is a minimum offer price calculated pursuant to Section III.1.10.1A(f).

Demand Resource On-Peak Hours are hours ending 1400 through 1700, Monday through Friday on non-Demand Response Holidays during the months of June, July, and August and hours ending 1800 through 1900, Monday through Friday on non-Demand Response Holidays during the months of December and January.

Demand Resource Seasonal Peak Hours are those hours in which the actual, real-time hourly load, as measured using real-time telemetry (adjusted for transmission and distribution losses, and excluding load associated with Exports and Storage DARDs) for Monday through Friday on non-Demand Response Holidays, during the months of June, July, August, December, and January, as determined by the ISO, is

equal to or greater than 90% of the most recent 50/50 system peak load forecast, as determined by the ISO, for the applicable summer or winter season.

Demand Response Asset is an asset comprising the demand reduction capability of an individual end-use customer at a Retail Delivery Point or the aggregated demand reduction capability of multiple end-use customers from multiple delivery points (as described in Section III.8.1.1(f)) that has been registered in accordance with III.8.1.1.

Demand Response Available is the capability of the Demand Response Resource, in whole or in part, at any given time, to reduce demand in response to a Dispatch Instruction.

Demand Response Baseline is the expected baseline demand of an individual end-use metered customer or group of end-use metered customers as determined pursuant to Section III.8.2.

Demand Response Holiday is New Year's Day, Memorial Day, Independence Day, Labor Day, Veterans Day, Thanksgiving Day, and Christmas Day. If the holiday falls on a Saturday, the holiday will be observed on the preceding Friday; if the holiday falls on a Sunday, the holiday will be observed on the following Monday.

Demand Response Resource is an individual Demand Response Asset or aggregation of Demand Response Assets within a DRR Aggregation Zone that has been registered in accordance with Section III.8.1.2.

Demand Response Resource Notification Time is the period of time between the receipt of a startup Dispatch Instruction and the time the Demand Response Resource starts reducing demand.

Demand Response Resource Ramp Rate is the average rate, expressed in MW per minute, at which the Demand Response Resource can reduce demand.

Demand Response Resource Start-Up Time is the period of time between the time a Demand Response Resource starts reducing demand at the conclusion of the Demand Response Resource Notification Time and the time the resource can reach its Minimum Reduction and be ready for further dispatch by the ISO.

Designated Agent is any entity that performs actions or functions required under the OATT on behalf of the ISO, a Transmission Owner, a Schedule 20A Service Provider, an Eligible Customer, or a Transmission Customer.

Designated Blackstart Resource is a resource that meets the eligibility requirements specified in Schedule 16 of the OATT, which includes any resource referred to previously as a Category B Designated Blackstart Resource.

Designated Entity is the entity designated by a Market Participant to receive Dispatch Instructions for a Generator Asset and/or Dispatchable Asset Related Demand in accordance with the provisions set forth in ISO New England Operating Procedure No. 14.

Designated FCM Participant is any Lead Market Participant, including any Provisional Member that is a Lead Market Participant, transacting in any Forward Capacity Auction, reconfiguration auctions or Capacity Supply Obligation Bilateral for capacity that is otherwise required to provide additional financial assurance under the ISO New England Financial Assurance Policy.

Designated FTR Participant is a Market Participant, including FTR-Only Customers, transacting in the FTR Auction that is otherwise required to provide additional financial assurance under the ISO New England Financial Assurance Policy.

Desired Dispatch Point (DDP) means the control signal, expressed in megawatts, transmitted to direct the output, consumption, or demand reduction level of each Generator Asset, Dispatchable Asset Related Demand, or Demand Response Resource dispatched by the ISO in accordance with the asset's Offer Data.

Direct Assignment Facilities are facilities or portions of facilities that are constructed for the sole use/benefit of a particular Transmission Customer requesting service under the OATT or a Generator Owner requesting an interconnection. Direct Assignment Facilities shall be specified in a separate agreement among the ISO, Interconnection Customer and Transmission Customer, as applicable, and the Transmission Owner whose transmission system is to be modified to include and/or interconnect with the Direct Assignment Facilities, shall be subject to applicable Commission requirements, and shall be paid for by the Customer in accordance with the applicable agreement and the Tariff.

Directly Metered Assets are specifically measured by OP-18 compliant metering as currently described in Section IV (Metering and Recording for Settlements) of OP-18. Directly Metered Assets include all Tie-Line Assets, all Generator Assets, as well as some Load Assets. Load Assets for which the Host Participant is not the Assigned Meter Reader are considered Directly Metered Assets. In addition, the Host Participant Assigned Meter Reader determines which additional Load Assets are considered Directly Metered Assets and which ones are considered Profiled Load Assets based upon the Host Participant Assigned Meter Reader reporting systems and process by which the Host Participant Assigned Meter Reader allocates non-PTF losses.

Disbursement Agreement is the Rate Design and Funds Disbursement Agreement among the PTOs, as amended and restated from time to time.

Dispatch Instruction means directions given by the ISO to Market Participants, which may include instructions to start up, shut down, raise or lower generation, curtail or restore loads from Demand Response Resources, change External Transactions, or change the status or consumption of a Dispatchable Asset Related Demand in accordance with the Supply Offer, Demand Bid, or Demand Reduction Offer parameters. Such instructions may also require a change to the operation of a Pool Transmission Facility. Such instructions are given through either electronic or verbal means.

Dispatch Zone means a subset of Nodes located within a Load Zone established by the ISO for each Capacity Commitment Period pursuant to Section III.12.4A.

Dispatchable Asset Related Demand (DARD) is an Asset Related Demand that is capable of having its energy consumption modified in Real-Time in response to Dispatch Instructions. A DARD must be capable of receiving and responding to electronic Dispatch Instructions, must be able to increase or decrease energy consumption between its Minimum Consumption Limit and Maximum Consumption Limit in accordance with Dispatch Instructions, and must meet the technical requirements specified in the ISO New England Operating Procedures and Manuals.

Dispatchable Resource is any Generator Asset, Dispatchable Asset Related Demand, Demand Response Resource, or, with respect to the Regulation Market only, Alternative Technology Regulation Resource, that, during the course of normal operation, is capable of receiving and responding to electronic Dispatch Instructions in accordance with the parameters contained in the Resource's Supply Offer, Demand Bid, Demand Reduction Offer or Regulation Service Offer. A Resource that is normally classified as a

Dispatchable Resource remains a Dispatchable Resource when it is temporarily not capable of receiving and responding to electronic Dispatch Instructions.

Dispute Representatives are defined in 6.5.c of the ISO New England Billing Policy.

Disputed Amount is a Covered Entity's disputed amount due on any fully paid monthly Invoice and/or any amount believed to be due or owed on a Remittance Advice, as defined in Section 6 of the ISO New England Billing Policy.

Disputing Party, for the purposes of the ISO New England Billing Policy, is any Covered Entity seeking to recover a Disputed Amount.

Distributed Generation means generation directly connected to end-use customer load and located behind the end-use customer's Retail Delivery Point that reduces the amount of energy that would otherwise have been produced on the electricity network in the New England Control Area, provided that the facility's Net Supply Capability is (i) less than 5 MW or (ii) less than or equal to the Maximum Facility Load, whichever is greater.

DRR Aggregation Zone is a Dispatch Zone entirely within a single Reserve Zone or Rest of System or, where a Dispatch Zone is not entirely within a single Reserve Zone or Rest of System, each portion of the Dispatch Zone demarcated by the Reserve Zone boundary.

Do Not Exceed (DNE) Dispatchable Generator is any Generator Asset that is dispatched using Do Not Exceed Dispatch Points in its Dispatch Instructions and meets the criteria specified in Section III.1.11.3(e). Do Not Exceed Dispatchable Generators are Dispatchable Resources.

Do Not Exceed Dispatch Point is a Dispatch Instruction indicating a maximum output level that a DNE Dispatchable Generator must not exceed.

Dynamic De-List Bid is a bid that may be submitted by Existing Generating Capacity Resources, Existing Import Capacity Resources, and Existing Demand Capacity Resources in the Forward Capacity Auction below the Dynamic De-List Bid Threshold, as described in Section III.13.2.3.2(d) of Market Rule 1.

Dynamic De-List Bid Threshold is the price specified in Section III.13.1.2.3.1.A of Market Rule 1 associated with the submission of Dynamic De-List Bids in the Forward Capacity Auction.

EA Amount is defined in Section IV.B.2.2 of the Tariff.

Early Amortization Charge (EAC) is defined in Section IV.B.2 of the Tariff.

Early Amortization Working Capital Charge (EAWCC) is defined in Section IV.B.2 of the Tariff.

Early Payment Shortfall Funding Amount (EPSF Amount) is defined in Section IV.B.2.4 of the Tariff.

Early Payment Shortfall Funding Charge (EPSFC) is defined in Section IV.B.2 of the Tariff.

EAWW Amount is defined in Section IV.B.2.3 of the Tariff.

EBITDA-to-Interest Expense Ratio is, on any date, a Market Participant's or Non-Market Participant Transmission Customer's earnings before interest, taxes, depreciation and amortization in the most recent fiscal quarter divided by that Market Participant's or Non-Market Participant Transmission Customer's expense for interest in that fiscal quarter, in each case as shown on the most recent financial statements provided by such Market Participant or Non-Market Participant Transmission Customer to the ISO.

Economic Dispatch Point is the output, reduction, or consumption level to which a Resource would have been dispatched, based on the Resource's Supply Offer, Demand Reduction Offer, or Demand Bid and the Real-Time Price, and taking account of any operating limits, had the ISO not dispatched the Resource to another Desired Dispatch Point.

Economic Maximum Limit or Economic Max is the maximum available output, in MW, of a Generator Asset that a Market Participant offers to supply in the Day-Ahead Energy Market or Real-Time Energy Market, as reflected in the Generator Asset's Offer Data. This represents the highest MW output a Market Participant has offered for a Generator Asset for economic dispatch. A Market Participant must maintain an up-to-date Economic Maximum Limit (and where applicable, must provide the ISO with any telemetry required by ISO New England Operating Procedure No. 18 to allow the ISO to maintain an

updated Economic Maximum Limit) for all hours in which a Generator Asset has been offered into the Day-Ahead Energy Market or Real-Time Energy Market.

Economic Minimum Limit or Economic Min is (a) for a Generator Asset with an incremental heat rate, the maximum of: (i) the lowest sustainable output level as specified by physical design characteristics, environmental regulations or licensing limits; and (ii) the lowest sustainable output level at which a one MW increment increase in the output level would not decrease the incremental cost, calculated based on the incremental heat rate, of providing an additional MW of output, and (b) for a Generator Asset without an incremental heat rate, the lowest sustainable output level that is consistent with the physical design characteristics of the Generator Asset and with meeting all environmental regulations and licensing limits, and (c) for a Generator Asset undergoing Facility and Equipment Testing or auditing, the level to which the Generator Asset requests and is approved to operate or is directed to operate for purposes of completing the Facility and Equipment Testing or auditing, and (d) for Non-Dispatchable Resources the output level at which a Market Participant anticipates its Non-Dispatchable Resource will be available to operate based on fuel limitations, physical design characteristics, environmental regulations or licensing limits.

Economic Study is defined in Section 4.1(b) of Attachment K to the OATT.

Effective Offer is the Supply Offer, Demand Reduction Offer, or Demand Bid that is used for NCPC calculation purposes as specified in Section III.F.1(a).

EFT is electronic funds transfer.

Elective Transmission Upgrade is defined in Section I of Schedule 25 of the OATT.

Elective Transmission Upgrade Interconnection Customer is defined in Schedule 25 of the OATT.

Electric Reliability Organization (ERO) is defined in 18 C.F.R. § 39.1.

Electric Storage Facility is a storage facility that participates in the New England Markets as described in Section III.1.10.6 of Market Rule 1.

Eligible Customer is: (i) Any entity that is engaged, or proposes to engage, in the wholesale or retail electric power business is an Eligible Customer under the OATT. (ii) Any electric utility (including any power marketer), Federal power marketing agency, or any other entity generating electric energy for sale or for resale is an Eligible Customer under the OATT. Electric energy sold or produced by such entity may be electric energy produced in the United States, Canada or Mexico. However, with respect to transmission service that the Commission is prohibited from ordering by Section 212(h) of the Federal Power Act, such entity is eligible only if the service is provided pursuant to a state requirement that the Transmission Owner with which that entity is directly interconnected or the distribution company having the service territory in which that entity is located (if that entity is a retail customer) offer the unbundled transmission service or Local Delivery Service, or pursuant to a voluntary offer of such service by the Transmission Owner with which that entity is directly interconnected or the distribution company having the service territory in which that entity is located (if that entity is a retail customer). (iii) Any end user taking or eligible to take unbundled transmission service or Local Delivery Service pursuant to a state requirement that the Transmission Owner with which that end user is directly interconnected or the distribution company having the service territory in which that entity is located (if that entity is a retail customer) offer the transmission service or Local Delivery Service, or pursuant to a voluntary offer of such service by the Transmission Owner with which that end user is directly interconnected, or the distribution company having the service territory in which that entity is located (if that entity is a retail customer) is an Eligible Customer under the OATT.

Eligible FTR Bidder is an entity that has satisfied applicable financial assurance criteria, and shall not include the auctioneer, its Affiliates, and their officers, directors, employees, consultants and other representatives.

Emergency is an abnormal system condition on the bulk power systems of New England or neighboring Control Areas requiring manual or automatic action to maintain system frequency, or to prevent the involuntary loss of load, equipment damage, or tripping of system elements that could adversely affect the reliability of an electric system or the safety of persons or property; or a fuel shortage requiring departure from normal operating procedures in order to minimize the use of such scarce fuel; or a condition that requires implementation of Emergency procedures as defined in the ISO New England Manuals.

Emergency Condition means an Emergency has been declared by the ISO in accordance with the procedures set forth in the ISO New England Manuals and ISO New England Administrative Procedures.

Emergency Energy is energy transferred from one control area operator to another in an Emergency.

Emergency Minimum Limit or Emergency Min means the minimum output, in MWs, that a Generator Asset can deliver for a limited period of time without exceeding specified limits of equipment stability and operating permits.

EMS is energy management system.

End-of-Round Price is the lowest price associated with a round of a Forward Capacity Auction, as described in Section III.13.2.3.1 of Market Rule 1.

End User Participant is defined in Section 1 of the Participants Agreement.

Energy is power produced in the form of electricity, measured in kilowatthours or megawatthours.

Energy Administration Service (EAS) is the service provided by the ISO, as described in Schedule 2 of Section IV.A of the Tariff.

Energy Call Option Offer is a form of offer that may be submitted by Market Participants in the Day-Ahead Energy Market in accordance with Section III.1.8 of Market Rule 1, and that is used by the ISO to determine obligations for Day-Ahead Ancillary Services as defined in Section III.3.2.1(a)(2) of Market Rule 1.

Energy Call Option Strike Price is specified in Section III.1.8. 3 of Market Rule 1.

Energy Component means the Locational Marginal Price at the reference point.

Energy Efficiency is installed measures (e.g., products, equipment, systems, services, practices and/or strategies) on end-use customer facilities that reduce the total amount of electrical energy needed, while delivering a comparable or improved level of end-use service. Such measures include, but are not limited to, the installation of more energy efficient lighting, motors, refrigeration, HVAC equipment and control systems, envelope measures, operations and maintenance procedures, and industrial process equipment.

Energy Imbalance Service is the form of Ancillary Service described in Schedule 4 of the OATT.

Energy Market is, collectively, the Day-Ahead Energy Market and the Real-Time Energy Market.

Energy Non-Zero Spot Market Settlement Hours are the sum of the hours for which the Customer has a positive or negative Real-Time System Adjusted Net Interchange or for which the Customer has a positive or negative Real-Time Demand Reduction Obligation as determined by the ISO settlement process for the Energy Market.

Energy Offer Floor is negative $150/MWh.

Energy Transaction Units (Energy TUs) are the sum for the month for a Customer of Bilateral Contract Block-Hours, Demand Bid Block-Hours, Asset Related Demand Bid Block-Hours, Supply Offer Block-Hours, Demand Reduction Offer Block-Hours, and Energy Non-Zero Spot Market Settlement Hours.

Equipment Damage Reimbursement is the compensation paid to the owner of a Designated Blackstart Resource as specified in Section 5.5 of Schedule 16 to the OATT.

Equivalent Demand Forced Outage Rate (EFORd) means the portion of time a unit is in demand, but is unavailable due to forced outages.

Estimated Capacity Load Obligation is, for the purposes of the ISO New England Financial Assurance Policy, a Market Participant's share of Zonal Capacity Obligation from the latest available month, adjusted as appropriate to account for any relevant Capacity Load Obligation Bilaterals, HQICCs, and Self-Supplied FCA Resource designations for the applicable month.

Establish Claimed Capability Audit is the audit performed pursuant to Section III.1.5.1.2.

Excepted Transaction is a transaction specified in Section II.40 of the Tariff for the applicable period specified in that Section.

Existing Capacity Qualification Deadline is a deadline, specified in Section III.13.1.10 of Market Rule 1, for submission of certain qualification materials for the Forward Capacity Auction, as discussed in Section III.13.1 of Market Rule 1.

Existing Capacity Qualification Package is information submitted for certain existing resources prior to participation in the Forward Capacity Auction, as described in Section III.13.1 of Market Rule 1.

Existing Capacity Resource is any resource that does not meet any of the eligibility criteria to participate in the Forward Capacity Auction as a New Capacity Resource.

Existing Capacity Retirement Deadline is a deadline, specified in Section III.13.1.10 of Market Rule 1, for submission of certain qualification materials for the Forward Capacity Auction, as discussed in Section III.13.1 of Market Rule 1.

Existing Capacity Retirement Package is information submitted for certain existing resources prior to participation in the Forward Capacity Auction, as described in Section III.13.1 of Market Rule 1.

Existing Demand Capacity Resource is a type of Demand Capacity Resource participating in the Forward Capacity Market, as defined in Section III.13.1.4.2 of Market Rule 1.

Existing Generating Capacity Resource is a type of resource participating in the Forward Capacity Market, as defined in Section III.13.1.2.1 of Market Rule 1.

Existing Import Capacity Resource is a type of resource participating in the Forward Capacity Market, as defined in Section III.13.1.3.1 of Market Rule 1.

Expedited Study Request is defined in Section II.34.7 of the OATT.

Export-Adjusted LSR is as defined in Section III.12.4(b)(ii).

Export Bid is a bid that may be submitted by certain resources in the Forward Capacity Auction to export capacity to an external Control Area, as described in Section III.13.1.2.3.1.3 of Market Rule 1.

Exports are Real-Time External Transactions, which are limited to sales from the New England Control Area, for exporting energy out of the New England Control Area.

External Elective Transmission Upgrade (External ETU) is defined in Section I of Schedule 25 of the OATT.

External Market Monitor means the person or entity appointed by the ISO Board of Directors pursuant to Section III.A.1.2 of Appendix A of Market Rule 1 to carry out the market monitoring and mitigation functions specified in Appendix A and elsewhere in Market Rule 1.

External Node is a proxy bus or buses used for establishing a Locational Marginal Price for energy received by Market Participants from, or delivered by Market Participants to, a neighboring Control Area or for establishing Locational Marginal Prices associated with energy delivered through the New England Control Area by Non-Market Participants for use in calculating Non-Market Participant Congestion Costs and loss costs.

External Resource means a generation resource located outside the metered boundaries of the New England Control Area.

External Transaction is the import of external energy into the New England Control Area by a Market Participant or the export of internal energy out of the New England Control Area by a Market Participant in the Day-Ahead Energy Market and/or Real-Time Energy Market, or the wheeling of external energy through the New England Control Area by a Market Participant or a Non-Market Participant in the Real-Time Energy Market.

External Transaction Cap is $2,000/MWh for External Transactions other than Coordinated External Transactions and $1,000/MWh for Coordinated External Transactions.

External Transaction Floor is the Energy Offer Floor for External Transactions other than Coordinated External Transactions and negative $1,000/MWh for Coordinated External Transactions.

External Transmission Project is a transmission project comprising facilities located wholly outside the New England Control Area and regarding which an agreement has been reached whereby New England ratepayers will support all or a portion of the cost of the facilities.

Facilities Study is an engineering study conducted pursuant to the OATT by the ISO (or, in the case of Local Service or interconnections to Local Area Facilities as defined in the TOA, by one or more affected PTOs) or some other entity designated by the ISO in consultation with any affected Transmission Owner(s), to determine the required modifications to the PTF and Non-PTF, including the cost and

scheduled completion date for such modifications, that will be required to provide a requested transmission service or interconnection on the PTF and Non-PTF.

Facility and Equipment Testing means operation of a Resource to evaluate the functionality of the facility or equipment utilized in the operation of the facility.

Failure to Maintain Blackstart Capability is a failure of a Blackstart Owner or Designated Blackstart Resource to meet the Blackstart Service Minimum Criteria or Blackstart Service obligations, but does not include a Failure to Perform During a System Restoration event.

Failure to Perform During a System Restoration is a failure of a Blackstart Owner or Designated Blackstart Resource to follow ISO or Local Control Center dispatch instructions or perform in accordance with the dispatch instructions or the Blackstart Service Minimum Criteria and Blackstart Service obligations, described within the ISO New England Operating Documents, during a restoration of the New England Transmission System.

Fast Start Demand Response Resource is a Demand Response Resource that meets the following criteria: (i) Minimum Reduction Time does not exceed one hour; (ii) Minimum Time Between Reductions does not exceed one hour; (iii) Demand Response Resource Start-Up Time plus Demand Response Resource Notification Time does not exceed 30 minutes; (iv) has personnel available to respond to Dispatch Instructions or has automatic remote response capability; and (v) is capable of receiving and acknowledging a Dispatch Instruction electronically.

Fast Start Generator means a Generator Asset that the ISO can dispatch to an on-line or off-line state through electronic dispatch and that meets the following criteria: (i) Minimum Run Time does not exceed one hour; (ii) Minimum Down Time does not exceed one hour; (iii) cold Notification Time plus cold Start-Up Time does not exceed 30 minutes; (iv) available for dispatch (when it is either in an on-line or off-line state) and manned or has automatic remote dispatch capability; and (v) capable of receiving and acknowledging a start-up or shut-down Dispatch Instruction electronically.

FCA Cleared Export Transaction is defined in Section III.1.10.7(f)(ii) of Market Rule 1.

FCA Qualified Capacity is the Qualified Capacity that is used in a Forward Capacity Auction.

FCM Capacity Charge Requirements are calculated in accordance with Section VII.C of the ISO New England Financial Assurance Policy.

FCM Charge Rate is calculated in accordance with Section VII.C of the ISO New England Financial Assurance Policy.

FCM Commercial Operation is defined in Section III.13.3.8 of Market Rule 1.

FCM Deposit is calculated in accordance with Section VII.B.1 of the ISO New England Financial Assurance Policy.

FCM Financial Assurance Requirements are described in Section VII of the ISO New England Financial Assurance Policy.

Final Forward Reserve Obligation is calculated in accordance with Section III.9.8(a) of Market Rule 1.

Financial Assurance Default results from a Market Participant or Non-Market Participant Transmission Customer's failure to comply with the ISO New England Financial Assurance Policy.

Financial Assurance Obligations relative to the ISO New England Financial Assurance Policy are determined in accordance with Section III.A(v) of the ISO New England Financial Assurance Policy.

Financial Transmission Right (FTR) is a financial instrument that evidences the rights and obligations specified in Sections III.5.2.2 and III.7 of the Tariff.

Firm Point-To-Point Service is service which is arranged for and administered between specified Points of Receipt and Delivery in accordance with Part II.C of the OATT.

Firm Transmission Service is Regional Network Service, Through or Out Service, service for Excepted Transactions, firm MTF Service, firm OTF Service, and firm Local Service.

Flexible DNE Dispatchable Generator is any DNE Dispatchable Generator that meets the following criteria: (i) Minimum Run Time does not exceed one hour; (ii) Minimum Down Time does not exceed one hour; and (iii) cold Notification Time plus cold Start-Up Time does not exceed 30 minutes.

Force Majeure - An event of Force Majeure means any act of God, labor disturbance, act of the public enemy or terrorists, war, invasion, insurrection, riot, fire, storm or flood, ice, explosion, breakage or accident to machinery or equipment, any curtailment, order, regulation or restriction imposed by governmental military or lawfully established civilian authorities, or any other cause beyond the control of the ISO, a Transmission Owner, a Schedule 20A Service Provider, or a Customer, including without limitation, in the case of the ISO, any action or inaction by a Customer, a Schedule 20A Service Provider, or a Transmission Owner, in the case of a Transmission Owner, any action or inaction by the ISO, any Customer, a Schedule 20A Service Provider, or any other Transmission Owner, in the case of a Schedule 20A Service Provider, any action or inaction by the ISO, any Customer, a Transmission Owner, or any other Schedule 20A Service Provider, and, in the case of a Transmission Customer, any action or inaction by the ISO, a Schedule 20A Service Provider, or any Transmission Owner.

Forecast Energy Requirement Demand Quantity is described in Section III.1.8.6 of Market Rule 1.

Forecast Energy Requirement Price is determined in accordance with Section III.2.6.2(a) of Market Rule 1.

Formal Warning is defined in Section III.B.4.1.1 of Appendix B of Market Rule 1.

Formula-Based Sanctions are defined in Section III.B.4.1.3 of Appendix B of Market Rule 1.

Forward Capacity Auction (FCA) is the annual Forward Capacity Market auction process described in Section III.13.2 of Market Rule 1.

Forward Capacity Auction Starting Price is calculated in accordance with Section III.13.2.4 of Market Rule 1.

Forward Capacity Market (FCM) is the forward market for procuring capacity in the New England Control Area, as described in Section III.13 of Market Rule 1.

Forward Energy Inventory Election is the total MWh value for which a Market Participant elects to be compensated at the forward rate in the inventoried energy program as described in Section III.K.1(d) of Market Rule 1.

Forward LNG Inventory Election is the portion of a Market Participant's Forward Energy Inventory Election attributed to liquefied natural gas in the inventoried energy program as described in Section III.K.1(d) of Market Rule 1.

Forward Reserve means TMNSR and TMOR purchased by the ISO on a forward basis on behalf of Market Participants as provided for in Section III.9 of Market Rule 1.

Forward Reserve Assigned Megawatts is the amount of Forward Reserve, in megawatts, that a Market Participant assigns to eligible Forward Reserve Resources to meet its Forward Reserve Obligation as defined in Section III.9.4.1 of Market Rule 1.

Forward Reserve Auction is the periodic auction conducted by the ISO in accordance with Section III.9 of Market Rule 1 to procure Forward Reserve.

Forward Reserve Auction Offers are offers to provide Forward Reserve to meet system and Reserve Zone requirements as submitted by a Market Participant in accordance with Section III.9.3 of Market Rule 1.

Forward Reserve Charge is a Market Participant's share of applicable system and Reserve Zone Forward Reserve costs attributable to meeting the Forward Reserve requirement as calculated in accordance with Section III.9.9 of Market Rule 1.

Forward Reserve Clearing Price is the clearing price for TMNSR or TMOR, as applicable, for the system and each Reserve Zone resulting from the Forward Reserve Auction as defined in Section III.9.4 of Market Rule 1.

Forward Reserve Credit is the credit received by a Market Participant that is associated with that Market Participant's Final Forward Reserve Obligation as calculated in accordance with Section III.9.8 of Market Rule 1.

Forward Reserve Delivered Megawatts are calculated in accordance with Section III.9.6.5 of Market Rule 1.

Forward Reserve Delivery Period is defined in Section III.9.1 of Market Rule 1.

Forward Reserve Failure-to-Activate Megawatts are calculated in accordance with Section III.9.7.2(a) of Market Rule 1.

Forward Reserve Failure-to-Activate Penalty is the penalty associated with a Market Participant's failure to activate Forward Reserve when requested to do so by the ISO and is defined in Section III.9.7.2 of Market Rule 1.

Forward Reserve Failure-to-Activate Penalty Rate is specified in Section III.9.7.2 of Market Rule 1.

Forward Reserve Failure-to-Reserve, as specified in Section III.9.7.1 of Market Rule 1, occurs when a Market Participant's Forward Reserve Delivered Megawatts for a Reserve Zone in an hour is less than that Market Participant's Forward Reserve Obligation for that Reserve Zone in that hour. Under these circumstances the Market Participant pays a penalty based upon the Forward Reserve Failure-to-Reserve Penalty Rate and that Market Participant's Forward Reserve Failure-to-Reserve Megawatts.

Forward Reserve Failure-to-Reserve Megawatts are calculated in accordance with Section III.9.7.1(a) of Market Rule 1.

Forward Reserve Failure-to-Reserve Penalty is the penalty associated with a Market Participant's failure to reserve Forward Reserve and is defined in Section III.9.7.1 of Market Rule 1.

Forward Reserve Failure-to-Reserve Penalty Rate is specified in Section III.9.7.1(b)(ii) of Market Rule 1.

Forward Reserve Fuel Index is the index or set of indices used to calculate the Forward Reserve Threshold Price as defined in Section III.9.6.2 of Market Rule 1.

Forward Reserve Heat Rate is the heat rate as defined in Section III.9.6.2 of Market Rule 1 that is used to calculate the Forward Reserve Threshold Price.

Forward Reserve Market is a market for forward procurement of two reserve products, Ten-Minute Non-Spinning Reserve (TMNSR) and Thirty-Minute Operating Reserve (TMOR).

Forward Reserve MWs are those megawatts assigned to specific eligible Forward Reserve Resources which convert a Forward Reserve Obligation into a Resource-specific obligation.

Forward Reserve Obligation is a Market Participant's amount, in megawatts, of Forward Reserve that cleared in the Forward Reserve Auction and adjusted, as applicable, to account for bilateral transactions that transfer Forward Reserve Obligations.

Forward Reserve Obligation Charge is defined in Section III.10.4 of Market Rule 1.

Forward Reserve Offer Cap is $9,000/megawatt-month.

Forward Reserve Payment Rate is defined in Section III.9.8 of Market Rule 1.

Forward Reserve Procurement Period is defined in Section III.9.1 of Market Rule 1.

Forward Reserve Qualifying Megawatts refer to all or a portion of a Forward Reserve Resource's capability offered into the Real-Time Energy Market at energy offer prices above the applicable Forward Reserve Threshold Price that are calculated in accordance with Section III.9.6.4 of Market Rule 1.

Forward Reserve Resource is a Resource that meets the eligibility requirements defined in Section III.9.5.2 of Market Rule 1 that has been assigned Forward Reserve Obligation by a Market Participant.

Forward Reserve Threshold Price is the minimum price at which assigned Forward Reserve Megawatts are required to be offered into the Real-Time Energy Market as calculated in Section III.9.6.2 of Market Rule 1.

FTR Auction is the periodic auction of FTRs conducted by the ISO in accordance with Section III.7 of Market Rule 1.

FTR Auction Revenue is the revenue collected from the sale of FTRs in FTR Auctions. FTR Auction Revenue is payable to FTR Holders who submit their FTRs for sale in the FTR Auction in accordance with Section III.7 of Market Rule 1 and to ARR Holders and Incremental ARR Holders in accordance with Appendix C of Market Rule 1.

FTR Credit Test Percentage is calculated in accordance with Section III.B.1(b) of the ISO New England Financial Assurance Policy.

FTR Financial Assurance Requirements are described in Section VI of the ISO New England Financial Assurance Policy.

FTR Holder is an entity that acquires an FTR through the FTR Auction to Section III.7 of Market Rule 1 and registers with the ISO as the holder of the FTR in accordance with Section III.7 of Market Rule 1 and applicable ISO New England Manuals.

FTR-Only Customer is a Market Participant that transacts in the FTR Auction and that does not participate in other markets or programs of the New England Markets. References in this Tariff to a "Non-Market Participant FTR Customers" and similar phrases shall be deemed references to an FTR-Only Customer.

FTR Settlement Risk Financial Assurance is an amount of financial assurance required by a Designated FTR Participant for each bid submission into an FTR Auction and for each bid awarded to the individual participant in an FTR Auction. This amount is calculated pursuant to Section VI.A of the ISO New England Financial Assurance Policy.

GADS Data means data submitted to the NERC for collection into the NERC's Generating Availability Data System (GADS).

Gap Request for Proposals (Gap RFP) is defined in Section III.11 of Market Rule 1.

Gas Day means a period of 24 consecutive hours beginning at 0900 hrs Central Time.

Generating Capacity Resource means a New Generating Capacity Resource or an Existing Generating Capacity Resource.

Generator Asset is a device (or a collection of devices) that is capable of injecting real power onto the grid that has been registered as a Generator Asset in accordance with the Asset Registration Process.

Generator Imbalance Service is the form of Ancillary Service described in Schedule 10 of the OATT.

Generator Interconnection Related Upgrade is an addition to or modification of the New England Transmission System (pursuant to Section II.47.1, Schedule 22 or Schedule 23 of the OATT) to effect the interconnection of a new generating unit or an existing generating unit whose energy capability or capacity capability is being materially changed and increased whether or not the interconnection is being effected to meet the Capacity Capability Interconnection Standard or the Network Capability Interconnection Standard. As to Category A Projects (as defined in Schedule 11 of the OATT), a Generator Interconnection Related Upgrade also includes an upgrade beyond that required to satisfy the Network Capability Interconnection Standard (or its predecessor) for which the Generator Owner has committed to pay prior to October 29, 1998.

Generator Owner is the owner, in whole or part, of a generating unit whether located within or outside the New England Control Area.

Good Utility Practice means any of the practices, methods and acts engaged in or approved by a significant portion of the electric utility industry during the relevant time period, or any of the practices, methods and acts which, in the exercise of reasonable judgment in light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety and expedition. Good Utility Practice is not intended to be limited to the optimum practice, method, or act to the exclusion of all others, but rather includes all acceptable practices, methods, or acts generally accepted in the region, including those practices required by Federal Power Act Section 215(a)(4).

Governance Only Member is defined in Section 1 of the Participants Agreement.

Governance Participant is defined in the Participants Agreement.

Governing Documents, for the purposes of the ISO New England Billing Policy, are the Transmission, Markets and Services Tariff and ISO Participants Agreement.

Governing Rating is the lowest corporate rating from any Rating Agency for that Market Participant, or, if the Market Participant has no corporate rating, then the lowest rating from any Rating Agency for that Market Participant’s senior unsecured debt.

Grandfathered Agreements (GAs) is a transaction specified in Section II.45 for the applicable period specified in that Section.

Grandfathered Intertie Agreement (GIA) is defined pursuant to the TOA.

Handy-Whitman Index of Public Utility Construction Costs is the Total Other Production Plant index shown in the Cost Trends of Electric Utility Construction for the North Atlantic Region as published in the Handy-Whitman Index of Public Utility Construction Costs.

Highgate Transmission Facilities (HTF) are existing U. S.-based transmission facilities covered under the Agreement for Joint Ownership, Construction and Operation of the Highgate Transmission Interconnection dated as of August 1, 1984 including (1) the whole of a 200 megawatt high-voltage, back-to-back, direct-current converter facility located in Highgate, Vermont and (2) a 345 kilovolt transmission line within Highgate and Franklin, Vermont (which connects the converter facility at the U.S.-Canadian border to a Hydro-Quebec 120 kilovolt line in Bedford, Quebec). The HTF include any upgrades associated with increasing the capacity or changing the physical characteristics of these facilities as defined in the above stated agreement dated August 1, 1984 until the Operations Date, as defined in the TOA. The current HTF rating is a nominal 225 MW. The HTF are not defined as PTF. Coincident with the Operations Date and except as stipulated in Schedules, 9, 12, and Attachment F to the OATT, HTF shall be treated in the same manner as PTF for purposes of the OATT and all references to PTF in the OATT shall be deemed to apply to HTF as well. The treatment of the HTF is not intended to establish any binding precedent or presumption with regard to the treatment for other transmission facilities within the New England Transmission System (including HVDC, MTF, or Control Area Interties) for purposes of the OATT.

Host Participant or Host Utility is a Market Participant or a Governance Participant transmission or distribution provider that reconciles the loads within the metering domain with OP-18 compliant metering.

Hourly Charges are defined in Section 1.3 of the ISO New England Billing Policy.

Hourly PER is calculated in accordance with Section III.13.7.1.2.1 of Market Rule 1.

Hourly Requirements are determined in accordance with Section III.A(i) of the ISO New England Financial Assurance Policy.

Hourly Shortfall NCPC Credit is an NCPC Credit calculated pursuant to Appendix F to Market Rule 1.

Hub is a specific set of pre-defined Nodes for which a Locational Marginal Price will be calculated for the Day-Ahead Energy Market and Real-Time Energy Market and which can be used to establish a reference price for energy purchases and the transfer of Day-Ahead Adjusted Load Obligations and Real-Time Adjusted Load Obligations and for the designation of FTRs.

Hub Price is calculated in accordance with Section III.2.8 of Market Rule 1.

HQ Interconnection Capability Credit (HQICC) is a monthly value reflective of the annual installed capacity benefits of the Phase I/II HVDC-TF, as determined by the ISO, using a standard methodology on file with the Commission, in conjunction with the setting of the Installed Capacity Requirement. An appropriate share of the HQICC shall be assigned to an IRH if the Phase I/II HVDC-TF support costs are paid by that IRH and such costs are not included in the calculation of the Regional Network Service rate. The share of HQICC allocated to such an eligible IRH for a month is the sum in kilowatts of (1)(a) the IRH's percentage share, if any, of the Phase I Transfer Capability times (b) the Phase I Transfer Credit, plus (2)(a) the IRH's percentage share, if any, of the Phase II Transfer Capability, times (b) the Phase II Transfer Credit. The ISO shall establish appropriate HQICCs to apply for an IRH which has such a percentage share.

Import Capacity Resource means an Existing Import Capacity Resource or a New Import Capacity Resource offered to provide capacity in the New England Control Area from an external Control Area.

Inadvertent Energy Revenue is defined in Section III.3.2.1(o) of Market Rule 1.

Inadvertent Energy Revenue Charges or Credits is defined in Section III.3.2.1(p) of Market Rule 1.

Inadvertent Interchange means the difference between net actual energy flow and net scheduled energy flow into or out of the New England Control Area.

Increment Offer means an offer to sell energy at a specified Location in the Day-Ahead Energy Market which is not associated with a physical supply. An accepted Increment Offer results in scheduled supply at the specified Location in the Day-Ahead Energy Market.

Incremental ARR is an ARR provided in recognition of a participant-funded transmission system upgrade pursuant to Appendix C of this Market Rule.

Incremental ARR Holder is an entity which is the record holder of an Incremental Auction Revenue Right in the register maintained by the ISO.

Incremental Cost of Reliability Service is described in Section III.13.2.5.2.5.2 of Market Rule 1.

Independent Transmission Company (ITC) is a transmission entity that assumes certain responsibilities in accordance with Section 10.05 of the Transmission Operating Agreement and Attachment M to the OATT, subject to the acceptance or approval of the Commission and a finding of the Commission that the transmission entity satisfies applicable independence requirements.

Information Request is a request from a potential Disputing Party submitted in writing to the ISO for access to Confidential Information.

Initial Market Participant Financial Assurance Requirement is calculated for new Market Participants and Returning Market Participants, other than an FTR-Only Customer or a Governance Only Member, according to Section IV of the ISO New England Financial Assurance Policy.

Installed Capacity Requirement means the level of capacity required to meet the reliability requirements defined for the New England Control Area, as described in Section III.12 of Market Rule 1.

Interchange Transactions are transactions deemed to be effected under Market Rule 1.

Interconnecting Transmission Owner has the meaning specified in Section I of Schedule 22, Attachment 1 to Schedule 23, and Section I of Schedule 25 of the OATT.

Interconnection Agreement is the "Large Generator Interconnection Agreement", the "Small Generator Interconnection Agreement", or the "Elective Transmission Upgrade Interconnection Agreement"

pursuant to Schedules 22, 23 or 25 of the ISO OATT or an interconnection agreement approved by the Commission prior to the adoption of the Interconnection Procedures.

Interconnection Customer has the meaning specified in Section I of Schedule 22, Attachment 1 to Schedule 23, and Section I of Schedule 25 of the OATT.

Interconnection Feasibility Study Agreement has the meaning specified in Section I of Schedule 22, Attachment 1 to Schedule 23, or Section I of Schedule 25 of the OATT.

Interconnection Procedure is the "Large Generator Interconnection Procedures", the "Small Generator Interconnection Procedures", or the "Elective Transmission Upgrade Interconnection Procedures" pursuant to Schedules 22, 23, and 25 of the ISO OATT.

Interconnection Reliability Operating Limit (IROL) has the meaning specified in the Glossary of Terms Used in NERC Reliability Standards.

Interconnection Request has the meaning specified in Section I of Schedule 22, Attachment 1 to Schedule 23, or Section I of Schedule 25 of the OATT.

Interconnection Rights Holder(s) (IRH) has the meaning given to it in Schedule 20A to Section II of this Tariff.

Interconnection System Impact Study Agreement has the meaning specified in Section I of Schedule 22, Attachment 1 to Schedule 23 and Section I of Schedule 25 of the OATT.

Interest is interest calculated in the manner specified in Section II.8.3.

Interface Bid is a unified real-time bid to simultaneously purchase and sell energy on each side of an external interface for which the enhanced scheduling procedures in Section III.1.10.7.A are implemented.

Intermittent Power Resource is a wind, solar, run of river hydro or other renewable resource that does not have control over its net power output.

Internal Bilateral for Load is an internal bilateral transaction under which the buyer receives a reduction in Real-Time Load Obligation and the seller receives a corresponding increase in Real-Time Load Obligation in the amount of the sale, in MWs. An Internal Bilateral for Load transaction is only applicable in the Real-Time Energy Market.

Internal Bilateral for Market for Energy is an internal bilateral transaction for Energy which applies in the Day-Ahead Energy Market and Real-Time Energy Market or just the Real-Time Energy Market under which the buyer receives a reduction in Day-Ahead Adjusted Load Obligation and Real-Time Adjusted Load Obligation and the seller receives a corresponding increase in Day-Ahead Adjusted Load Obligation and Real-Time Adjusted Load Obligation in the amount of the sale, in MWs.

Internal Elective Transmission Upgrade (Internal ETU) is defined in Section I of Schedule 25 of the OATT.

Internal Market Monitor means the department of the ISO responsible for carrying out the market monitoring and mitigation functions specified in Appendix A and elsewhere in Market Rule 1.

Interregional Planning Stakeholder Advisory Committee (IPSAC) is the committee described as such in the Northeast Planning Protocol.

Interregional Transmission Project is a transmission project located within the New England Control Area and one or more of the neighboring transmission planning regions.

Interruption Cost is the amount, in dollars, that must be paid to a Market Participant each time the Market Participant's Demand Response Resource is scheduled or dispatched in the New England Markets to reduce demand.

Inventoried Energy Day is an Operating Day that occurs in the months of December, January, or February during the winter of 2023-2024 (inventoried energy program) and for which the average of the high temperature and the low temperature on that Operating Day, as measured and reported by the National Weather Service at Bradley International Airport in Windsor Locks, Connecticut, is less than or equal to 17 degrees Fahrenheit, as described in Section III.K.3.1 of Market Rule 1.

Investment Grade Rating, for a Market (other than an FTR-Only Customer) or Non-Market Participant Transmission Customer, is either (a) a corporate investment grade rating from one or more of the Rating Agencies, or (b) if the Market Participant or Non-Market Participant Transmission Customer does not have a corporate rating from one of the Rating Agencies, then an investment grade rating for the Market Participant's or Non-Market Participant Transmission Customer's senior unsecured debt from one or more of the Rating Agencies.

Invoice is a statement issued by the ISO for the net Charge owed by a Covered Entity pursuant to the ISO New England Billing Policy.

Invoice Date is the day on which the ISO issues an Invoice.

ISO means ISO New England Inc.

ISO Charges, for the purposes of the ISO New England Billing Policy, are both Non-Hourly Charges and Hourly Charges.

ISO Control Center is the primary control center established by the ISO for the exercise of its Operating Authority and the performance of functions as an RTO.

ISO-Initiated Claimed Capability Audit is the audit performed pursuant to Section III.1.5.1.4.

ISO New England Administrative Procedures means procedures adopted by the ISO to fulfill its responsibilities to apply and implement ISO New England System Rules.

ISO New England Billing Policy is Exhibit ID to Section I of the Transmission, Markets and Services Tariff.

ISO New England Filed Documents means the Transmission, Markets and Services Tariff, including but not limited to Market Rule 1, the Participants Agreement, the Transmission Operating Agreement or other documents that affect the rates, terms and conditions of service.

ISO New England Financial Assurance Policy is Exhibit IA to Section I of the Transmission, Markets and Services Tariff.

ISO New England Information Policy is the policy establishing guidelines regarding the information received, created and distributed by Market Participants and the ISO in connection with the settlement, operation and planning of the System, as the same may be amended from time to time in accordance with the provisions of this Tariff. The ISO New England Information Policy is Attachment D to the Transmission, Markets and Services Tariff.

ISO New England Manuals are the manuals implementing Market Rule 1, as amended from time to time in accordance with the Participants Agreement. Any elements of the ISO New England Manuals that substantially affect rates, terms, and/or conditions of service shall be filed with the Commission under Section 205 of the Federal Power Act.

ISO New England Operating Documents are the Tariff and the ISO New England Operating Procedures.

ISO New England Operating Procedures (OPs) are the ISO New England Planning Procedures and the operating guides, manuals, procedures and protocols developed and utilized by the ISO for operating the ISO bulk power system and the New England Markets.

ISO New England Planning Procedures are the procedures developed and utilized by the ISO for planning the ISO bulk power system.

ISO New England System Rules are Market Rule 1, the ISO New England Information Policy, the ISO New England Administrative Procedures, the ISO New England Manuals and any other system rules, procedures or criteria for the operation of the New England Transmission System and administration of the New England Markets and the Transmission, Markets and Services Tariff.

ITC Agreement is defined in Attachment M to the OATT.

ITC Rate Schedule is defined in Section 3.1 of Attachment M to the OATT.

ITC System is defined in Section 2.2 of Attachment M to the OATT.

ITC System Planning Procedures is defined in Section 15.4 of Attachment M to the OATT.

Joint ISO/RTO Planning Committee (JIPC) is the committee described as such in the Northeastern Planning Protocol.

Late Payment Account is a segregated interest-bearing account into which the ISO deposits Late Payment Charges due from ISO Charges and interest owed from participants for late payments that are collected and not distributed to the Covered Entities, until the Late Payment Account Limit is reached, under the ISO New England Billing Policy and penalties collected under the ISO New England Financial Assurance Policy.

Late Payment Account Limit is defined in Section 4.2 of the ISO New England Billing Policy.

Late Payment Charge is defined in Section 4.1 of the ISO New England Billing Policy.

Lead Market Participant, for purposes other than the Forward Capacity Market, is the entity authorized to submit Supply Offers, Demand Bids or Demand Reduction Offers for a Resource and to whom certain Energy TUs are assessed under Schedule 2 of Section IV.A of the Tariff. For purposes of the Forward Capacity Market, the Lead Market Participant is the entity designated to participate in that market on behalf of an Existing Capacity Resource or a New Capacity Resource.

Limited Energy Resource means a Generator Asset that, due to design considerations, environmental restriction on operations, cyclical requirements, such as the need to recharge or refill or manage water flow, or fuel limitations, are unable to operate continuously at full output on a daily basis.

Load Asset means a physical load that has been registered in accordance with the Asset Registration Process. A Load Asset can be an Asset Related Demand, including a Dispatchable Asset Related Demand.

Load Management means measures (e.g., products, equipment, systems, services, practices and/or strategies) on end-use customer facilities that curtail electrical usage or shift electrical usage while delivering a comparable or acceptable level of end-use service. Such measures include, but are not limited to, energy management systems, load control end-use cycling, load curtailment strategies, and energy storage that curtails or shifts electrical usage by means other than generating electricity.

Load Shedding is the systematic reduction of system demand by temporarily decreasing load.

Load Zone is a Reliability Region, except as otherwise provided for in Section III.2.7 of Market Rule 1.

Local Area Facilities are defined in the TOA**.**

Local Benefit Upgrade(s) (LBU) is an upgrade, modification or addition to the transmission system that is: (i) rated below 115kV or (ii) rated 115kV or above and does not meet all of the non-voltage criteria for PTF classification specified in the OATT.

Local Control Centers are those control centers in existence as of the effective date of the OATT (including the CONVEX, REMVEC, Maine and New Hampshire control centers) or established by the PTOs in accordance with the TOA that are separate from the ISO Control Center and perform certain functions in accordance with the OATT and the TOA.

Local Delivery Service is the service of delivering electric energy to end users. This service is subject to state jurisdiction regardless of whether such service is provided over local distribution or transmission facilities. An entity that is an Eligible Customer under the OATT is not excused from any requirements of state law, or any order or regulation issued pursuant to state law, to arrange for Local Delivery Service with the Participating Transmission Owner and/or distribution company providing such service and to pay all applicable charges associated with such service, including charges for stranded costs and benefits.

Local Network is defined as the transmission facilities constituting a local network as identified in Attachment E, as such Attachment may be modified from time to time in accordance with the Transmission Operating Agreement.

Local Network Load is the load that a Network Customer designates for Local Network Service under Schedule 21 to the OATT.

Local Network RNS Rate is the rate applicable to Regional Network Service to effect a delivery to load in a particular Local Network, as determined in accordance with Schedule 9 to the OATT.

Local Network Service (LNS) is the network service provided under Schedule 21 and the Local Service Schedules to permit the Transmission Customer to efficiently and economically utilize its resources to serve its load.

Local Point-To-Point Service (LPTP) is Point-to-Point Service provided under Schedule 21 of the OATT and the Local Service Schedules to permit deliveries to or from an interconnection point on the PTF.

Local Public Policy Transmission Upgrade is any addition and/or upgrade to the New England Transmission System with a voltage level below 115kV that is required in connection with the construction of a Public Policy Transmission Upgrade approved for inclusion in the Regional System Plan pursuant to Attachment K to the ISO OATT or included in a Local System Plan in accordance with Appendix 1 to Attachment K.

Local Resource Adequacy Requirement is calculated pursuant to Section III.12.2.1.1.

Local Second Contingency Protection Resources are those Resources identified by the ISO on a daily basis as necessary for the provision of Operating Reserve requirements and adherence to NERC, NPCC and ISO reliability criteria over and above those Resources required to meet first contingency reliability criteria within a Reliability Region.

Local Service is transmission service provided under Schedule 21 and the Local Service Schedules thereto.

Local Service Schedule is a PTO-specific schedule to the OATT setting forth the rates, charges, terms and conditions applicable to Local Service.

Local Sourcing Requirement (LSR) is a value calculated as described in Section III.12.2.1 of Market Rule 1.

Local System Planning (LSP) is the process defined in Appendix 1 of Attachment K to the OATT.

Localized Costs are costs that the ISO, with advisory input from the Reliability Committee, determines in accordance with Schedule 12C of the OATT shall not be included in the Pool-Supported PTF costs

recoverable under this OATT, or in costs allocated to Regional Network Load according to Section 6 of Schedule 12. If there are any Localized Costs, the ISO shall identify them in the Regional System Plan.

Location is a Node, External Node, Load Zone, DRR Aggregation Zone, or Hub.

Locational Marginal Price (LMP) is defined in Section III.2 of Market Rule 1. The Locational Marginal Price for a Node is the nodal price at that Node; the Locational Marginal Price for an External Node is the nodal price at that External Node; the Locational Marginal Price for a Load Zone, DRR Aggregation Zone or Reliability Region is the Zonal Price for that Load Zone, DRR Aggregation Zone or Reliability Region, respectively; and the Locational Marginal Price for a Hub is the Hub Price for that Hub.

Long Lead Time Facility (Long Lead Facility) has the meaning specified in Section I of Schedule 22 and Schedule 25 of the OATT.

Long-Term is a term of one year or more.

Long-Term Transmission Outage is a long-term transmission outage scheduled in accordance with ISO New England Operating Procedure No. 3.

Loss Component is the component of the nodal LMP at a given Node or External Node on the PTF that reflects the cost of losses at that Node or External Node relative to the reference point. The Loss Component of the nodal LMP at a given Node on the non-PTF system reflects the relative cost of losses at that Node adjusted as required to account for losses on the non-PTF system already accounted for through tariffs associated with the non-PTF. When used in connection with Hub Price or Zonal Price, the term Loss Component refers to the Loss Components of the nodal LMPs that comprise the Hub Price or Zonal Price, which Loss Components are averaged or weighted in the same way that nodal LMPs are averaged to determine Hub Price or weighted to determine Zonal Price.

Loss of Load Expectation (LOLE) is the probability of disconnecting non-interruptible customers due to a resource deficiency.

Lost Opportunity Cost (LOC) is one of four forms of compensation that may be paid to resources providing VAR Service under Schedule 2 of the OATT.

LSE means load serving entity.

Lump Sum Blackstart Payment is defined and calculated as specified in Section 5.4 of Schedule 16 to the OATT.

Lump Sum Blackstart Capital Payment is defined and calculated as specified in Section 5.4 of Schedule 16 to the OATT.

Manual Response Rate is the rate, in MW/Minute, at which the output of a Generator Asset, or the consumption of a Dispatchable Asset Related Demand, is capable of changing.

Marginal Loss Revenue Load Obligation is defined in Section III.3.2.1(b) of Market Rule 1.

Marginal Reliability Impact is the change, with respect to an increment of capacity supply, in expected unserved energy due to resource deficiency, as measured in hours per year.

Market Credit Limit is a credit limit for a Market Participant's Financial Assurance Obligations (except FTR Financial Assurance Requirements) established for each Market Participant in accordance with Section II.C of the ISO New England Financial Assurance Policy.

Market Credit Test Percentage is calculated in accordance with Section III.B.1(a) of the ISO New England Financial Assurance Policy.

Market Efficiency Transmission Upgrade is defined as those additions and upgrades that are not related to the interconnection of a generator, and, in the ISO's determination, are designed to reduce bulk power system costs to load system-wide, where the net present value of the reduction in bulk power system costs to load system-wide exceeds the net present value of the cost of the transmission addition or upgrade. For purposes of this definition, the term "bulk power system costs to load system-wide" includes, but is not limited to, the costs of energy, capacity, reserves, losses and impacts on bilateral prices for electricity.

Market Participant is a participant in the New England Markets (including a FTR-Only Customer) that has executed a Market Participant Service Agreement, or on whose behalf an unexecuted Market Participant Service Agreement has been filed with the Commission.

Market Participant Financial Assurance Requirement is defined in Section III of the ISO New England Financial Assurance Policy.

Market Participant Obligations is defined in Section III.B.1.1 of Appendix B of Market Rule 1.

Market Participant Service Agreement (MPSA) is an agreement between the ISO and a Market Participant, in the form specified in Attachment A or Attachment A-1 to the Tariff, as applicable.

Market Rule 1 is ISO Market Rule 1 and appendices set forth in Section III of this ISO New England Inc. Transmission, Markets and Services Tariff, as it may be amended from time to time.

Market Violation is a tariff violation, violation of a Commission-approved order, rule or regulation, market manipulation, or inappropriate dispatch that creates substantial concerns regarding unnecessary market inefficiencies.

Material Adverse Change is any change in financial status including, but not limited to a downgrade to below an Investment Grade Rating by any Rating Agency, being placed on credit watch with negative implication by any Rating Agency if the Market Participant or Non-Market Participant Transmission Customer does not have an Investment Grade Rating, a bankruptcy filing or other insolvency, a report of a significant quarterly loss or decline of earnings, the resignation of key officer(s), the sanctioning of the Market Participant or Non-Market Participant Transmission Customer or any of its Principles imposed by the Federal Energy Regulatory Commission, the Securities Exchange Commission, any exchange monitored by the National Futures Association, or any state entity responsible for regulating activity in energy markets; the filing of a material lawsuit that could materially adversely impact current or future financial results; a significant change in the Market Participant's or Non-Market Participant Transmission Customer's credit default spreads; or a significant change in market capitalization.

Material Adverse Impact is defined, for purposes of review of ITC-proposed plans, as a proposed facility or project will be deemed to cause a "material adverse impact" on facilities outside of the ITC System if: (i) the proposed facility or project causes non-ITC facilities to exceed their capabilities or

exceed their thermal, voltage or stability limits, consistent with all applicable reliability criteria, or (ii) the proposed facility or project would not satisfy the standards set forth in Section I.3.9 of the Transmission, Markets and Services Tariff. This standard is intended to assure the continued service of all non-ITC firm load customers and the ability of the non-ITC systems to meet outstanding transmission service obligations.

Maximum Capacity Limit is a value calculated as described in Section III.12.2.2 of Market Rule 1.

Maximum Consumption Limit is the maximum amount, in MW, available for economic dispatch from a DARD and is based on the physical characteristics as submitted as part of the DARD's Offer Data. A Market Participant must maintain an up-to-date Maximum Consumption Limit (and where applicable, must provide the ISO with any telemetry required by ISO New England Operating Procedure No. 18 to allow the ISO to maintain an updated Maximum Consumption Limit) for all hours in which a DARD has been offered into the Day-Ahead Energy Market or Real-Time Energy Market.

Maximum Daily Energy Limit is the maximum amount of megawatt-hours that a Limited Energy Resource expects to be able to generate in the next Operating Day.

Maximum Daily Consumption Limit is the maximum amount of megawatt-hours that a Storage DARD expects to be able to consume in the next Operating Day.

Maximum Facility Load is the highest demand of an end-use customer facility since the start of the prior calendar year (or, if unavailable, an estimate thereof), where the demand evaluated is established by adding metered demand measured at the Retail Delivery Point and the output of all generators located behind the Retail Delivery Point in the same time intervals.

Maximum Interruptible Capacity is an estimate of the maximum demand reduction and Net Supply that a Demand Response Asset can deliver, as measured at the Retail Delivery Point.

Maximum Load is the highest demand since the start of the prior calendar year (or, if unavailable, an estimate thereof), as measured at the Retail Delivery Point.

Maximum Number of Daily Starts is the maximum number of times that a Binary Storage DARD or a Generator Asset can be started or that a Demand Response Resource can be interrupted in the next Operating Day under normal operating conditions.

Maximum Reduction is the maximum available demand reduction, in MW, of a Demand Response Resource that a Market Participant offers to deliver in the Day-Ahead Energy Market or Real-Time Energy Market, as reflected in the Demand Response Resource's Demand Reduction Offer.

Measure Life is the estimated time an On-Peak Demand Resource or Seasonal Peak Demand Resource measure will remain in place, or the estimated time period over which the facility, structure, equipment or system in which a measure is installed continues to exist, whichever is shorter. Suppliers of On-Peak Demand Resources or Seasonal Peak Demand Resources comprised of an aggregation of measures with varied Measures Lives shall determine and document the Measure Life either: (i) for each type of measure with a different Measure Life and adjust the aggregate performance based on the individual measure life calculation in the portfolio; or (ii) as the average Measure Life for the aggregated measures as long as the demand reduction capability of the resource is greater than or equal to the amount that cleared in the Forward Capacity Auction or reconfiguration auction for the entire Capacity Commitment Period, and the demand reduction capability for an Existing On-Peak Demand Resource or Existing Seasonal Peak Demand Resource is not over-stated in a subsequent Capacity Commitment Period. Measure Life shall be determined consistent with the resource's Measurement and Verification Plan, which shall be reviewed by the ISO to ensure consistency with the measurement and verification requirements of Market Rule 1 and the ISO New England Manuals.

Measurement and Verification Documents mean the measurement and verification documents described in Section 13.1.4.3.1 of Market Rule 1 that are submitted by On-Peak Demand Resources and Seasonal Peak Demand Resources, which include Measurement and Verification Plans, Updated Measurement and Verification Plans, Measurement and Verification Summary Reports, and Measurement and Verification Reference Reports.

Measurement and Verification Plan means the measurement and verification plan submitted by an On-Peak Demand Resource or Seasonal Peak Demand Resource as part of the qualification process for the Forward Capacity Auction pursuant to the requirements of Section III.13.1.4.3 of Market Rule 1 and the ISO New England Manuals.

Measurement and Verification Reference Reports are optional reports submitted by On-Peak Demand Resources or Seasonal Peak Demand Resources during the Capacity Commitment Period subject to the schedule in the Measurement and Verification Plan and consistent with the schedule and reporting standards set forth in the ISO New England Manuals. Measurement and Verification Reference Reports update the prospective demand reduction capability of the On-Peak Demand Resource or Seasonal Peak Demand Resource project based on measurement and verification studies performed during the Capacity Commitment Period.

Measurement and Verification Summary Report is the monthly report submitted by an On-Peak Demand Resource or Seasonal Peak Demand Resource with the monthly settlement report for the Forward Capacity Market, which documents the total demand reduction capability for all On-Peak Demand Resources and Seasonal Peak Demand Resources in operation as of the end of the previous month.

MEPCO Grandfathered Transmission Service Agreement (MGTSA) is a MEPCO long-term firm point-to-point transmission service agreement with a POR or POD at the New Brunswick border and a start date prior to June 1, 2007 where the holder has elected, by written notice delivered to MEPCO within five (5) days following the filing of the settlement agreement in Docket Nos. ER07-1289 and EL08-56 or by September 1, 2008 (whichever is later), MGTSA treatment as further described in Section II.45.1.

Merchant Transmission Facilities (MTF) are the transmission facilities owned by MTOs, defined and classified as MTF pursuant to Schedule 18 of the OATT, over which the ISO shall exercise Operating Authority in accordance with the terms set forth in a MTOA or Attachment K to the OATT, rated 69 kV or above and required to allow energy from significant power sources to move freely on the New England Transmission System.

Merchant Transmission Facilities Provider (MTF Provider) is an entity as defined in Schedule 18 of the OATT.

Merchant Transmission Facilities Service (MTF Service) is transmission service over MTF as provided for in Schedule 18 of the OATT.

Merchant Transmission Operating Agreement (MTOA) is an agreement between the ISO and an MTO with respect to its MTF.

Merchant Transmission Owner (MTO) is an owner of MTF.

Meter Data Error means an error in meter data, including an error in Coincident Peak Contribution values, on an Invoice issued by the ISO after the completion of the Data Reconciliation Process as described in the ISO New England Manuals and in Section III.3.8 of Market Rule 1.

Meter Data Error RBA Submission Limit means the date thirty 30 calendar days after the issuance of the Invoice containing the results of the Data Reconciliation Process as described in the ISO New England Manuals and in Section III.3.6 of Market Rule 1.

Metered Quantity For Settlement is defined in Section III.3.2.1.1 of Market Rule 1.

Minimum Consumption Limit is (a) the lowest consumption level, in MW, available for economic dispatch from a DARD and is based on the physical characteristics as submitted as part of the DARD's Offer Data, and (b) for a DARD undergoing Facility and Equipment Testing or auditing, the level to which the DARD requests and is approved to operate or is directed to operate for purposes of completing the Facility and Equipment Testing or auditing.

Minimum Down Time is the number of hours that must elapse after a Generator Asset or Storage DARD has been released for shutdown at or below its Economic Minimum Limit or Minimum Consumption Limit before the Generator Asset or Storage DARD can be brought online and be released for dispatch at its Economic Minimum Limit or Minimum Consumption Limit.

Minimum Generation Emergency means an Emergency declared by the ISO in which the ISO anticipates requesting one or more Generator Assets to operate at or below Economic Minimum Limit in order to manage, alleviate, or end the Emergency.

Minimum Generation Emergency Credits are those Real-Time Dispatch NCPC Credits calculated pursuant to Appendix F of Market Rule 1 for resources within a reliability region that are dispatched during a period for which a Minimum Generation Emergency has been declared.

Minimum Reduction is the minimum available demand reduction, in MW, of a Demand Response Resource that a Market Participant offers to deliver in the Day-Ahead Energy Market or Real-Time Energy Market, as reflected in the Demand Response Resource's Demand Reduction Offer.

Minimum Reduction Time is the minimum number of hours of demand reduction at or above the Minimum Reduction for which the ISO must dispatch a Demand Response Resource to reduce demand.

Minimum Run Time is the number of hours that a Generator Asset must remain online after it has been scheduled to reach its Economic Minimum Limit before it can be released for shutdown from its Economic Minimum Limit or the number of hours that must elapse after a Storage DARD has been scheduled to consume at its Minimum Consumption Limit before it can be released for shutdown.

Minimum Time Between Reductions is the number of hours that must elapse after a Demand Response Resource has received a Dispatch Instruction to stop reducing demand before the Demand Response Resource can achieve its Minimum Reduction after receiving a Dispatch Instruction to start reducing demand.

Minimum Total Reserve Requirement, which does not include Replacement Reserve, is the combined amount of TMSR, TMNSR, and TMOR required system-wide as described in Section III.2.7A and ISO New England Operating Procedure No. 8.

Monthly Blackstart Service Charge is the charge made to Transmission Customers pursuant to Section 6 of Schedule 16 to the OATT.

Monthly Capacity Payment is the Forward Capacity Market payment described in Section III.13.7.3 of Market Rule 1.

Monthly Peak is defined in Section II.21.2 of the OATT.

Monthly PER is calculated in accordance with Section III.13.7.1.2.2 of Market Rule 1.

Monthly Real-Time Demand Reduction Obligation is the absolute value of a Customer's hourly Real-Time Demand Reduction Obligation summed for all hours in a month, in MWhs.

Monthly Real-Time Generation Obligation is the sum, for all hours in a month, at all Locations, of a Customer's Real-Time Generation Obligation, in MWhs.

Monthly Real-Time Load Obligation is the absolute value of a Customer's hourly Real-Time Load Obligation summed for all hours in a month, in MWhs.

Monthly Regional Network Load is defined in Section II.21.2 of the OATT.

Monthly Statement is the first weekly Statement issued on a Monday after the tenth of a calendar month that includes both the Hourly Charges for the relevant billing period and Non-Hourly Charges for the immediately preceding calendar month.

MRI Transition Period is the period specified in Section III.13.2.2.1.

MUI is the market user interface.

Municipal Market Participant is defined in Section II of the ISO New England Financial Assurance Policy.

MW is megawatt.

MWh is megawatt-hour.

Native Load Customers are the wholesale and retail power customers of a Transmission Owner on whose behalf the Transmission Owner, by statute, franchise, regulatory requirement, or contract, has undertaken an obligation to construct and operate its system to meet the reliable electric needs of such customers.

NCPC Charge means the charges to Market Participants calculated pursuant to Appendix F to Market Rule 1.

NCPC Credit means the credits to Market Participants calculated pursuant to Appendix F to Market Rule 1.

Needs Assessment is defined in Section 4.1 of Attachment K to the OATT.

NEMA, for purposes of Section III of the Tariff, is the Northeast Massachusetts Reliability Region.

NEMA Contract is a contract described in Appendix C of Market Rule 1 and listed in Exhibit 1 of Appendix C of Market Rule 1.

NEMA Load Serving Entity (NEMA LSE) is a Transmission Customer or Congestion Paying LSE Entity that serves load within NEMA.

NEMA or Northeast Massachusetts Upgrade, for purposes of Section II of the Tariff, is an addition to or modification of the PTF into or within the Northeast Massachusetts Reliability Region that was not, as of December 31, 1999, the subject of a System Impact Study or application filed pursuant to Section I.3.9 of the Transmission, Markets and Services Tariff; that is not related to generation interconnections; and that will be completed and placed in service by June 30, 2004. Such upgrades include, but are not limited to, new transmission facilities and related equipment and/or modifications to existing transmission facilities and related equipment. The list of NEMA Upgrades is contained in Schedule 12A of the OATT.

NEPOOL is the New England Power Pool, and the entities that collectively participated in the New England Power Pool.

NEPOOL Agreement is the agreement among the participants in NEPOOL.

NEPOOL GIS is the generation information system.

NEPOOL GIS Administrator is the entity or entities that develop, administer, operate and maintain the NEPOOL GIS.

NEPOOL GIS API Fees are the one-time on-boarding fees and annual maintenance fees charged to NEPOOL by the NEPOOL GIS Administrator for each NEPOOL Participant or Market Participant that accesses the NEPOOL GIS through an application programming interface pursuant to Rule 3.9(b) of the operating rules of the NEPOOL GIS.

NEPOOL Participant is a party to the NEPOOL Agreement.

NERC is the North American Electric Reliability Corporation or its successor organization.

NESCOE is the New England States Committee on Electricity, recognized by the Commission as the regional state committee for the New England Control Area.

Net Commitment Period Compensation (NCPC) is the compensation methodology for Resources that is described in Appendix F to Market Rule 1.

Net CONE is an estimate of the Cost of New Entry, net of the first-year non-capacity market revenues, for a reference technology resource type and is intended to equal the amount of capacity revenue the reference technology resource would require, in its first year of operation, to be economically viable given reasonable expectations of the first year energy and ancillary services revenues, and projected revenue for subsequent years.

Net Regional Clearing Price is described in Section III.13.7.5 of Market Rule 1.

Net Supply is energy injected into the transmission or distribution system at a Retail Delivery Point.

Net Supply Capability is the maximum Net Supply a facility is physically and contractually able to inject into the transmission or distribution system at its Retail Delivery Point.

Network Capability Interconnection Standard has the meaning specified in Section I of Schedule 22, Attachment 1 to Schedule 23, and Section I of Schedule 25 of the OATT.

Network Customer is a Transmission Customer receiving RNS or LNS.

Network Import Capability (NI Capability) is defined in Section I of Schedule 25 of the OATT.

Network Import Interconnection Service (NI Interconnection Service) is defined in Section I of Schedule 25 of the OATT.

Network Resource is defined as follows: (1) With respect to Market Participants, (a) any generating resource located in the New England Control Area which has been placed in service prior to the

Compliance Effective Date (including a unit that has lost its capacity value when its capacity value is restored and a deactivated unit which may be reactivated without satisfying the requirements of Section II.46 of the OATT in accordance with the provisions thereof) until retired; (b) any generating resource located in the New England Control Area which is placed in service after the Compliance Effective Date until retired, provided that (i) the Generator Owner has complied with the requirements of Sections II.46 and II.47 and Schedules 22 and 23 of the OATT, and (ii) the output of the unit shall be limited in accordance with Sections II.46 and II.47 and Schedules 22 and 23, if required; and (c) any generating resource or combination of resources (including bilateral purchases) located outside the New England Control Area for so long as any Market Participant has an Ownership Share in the resource or resources which is being delivered to it in the New England Control Area to serve Regional Network Load located in the New England Control Area or other designated Regional Network Loads contemplated by Section II.18.3 of the OATT taking Regional Network Service. (2) With respect to Non-Market Participant Transmission Customers, any generating resource owned, purchased or leased by the Non-Market Participant Transmission Customer which it designates to serve Regional Network Load.

New Brunswick Security Energy is defined in Section III.3.2.6A of Market Rule 1.

New Capacity Offer is an offer in the Forward Capacity Auction to provide capacity from a New Generating Capacity Resource, New Import Capacity Resource or New Demand Capacity Resource.

New Capacity Qualification Deadline is a deadline, specified in Section III.13.1.10 of Market Rule 1, for submission of certain qualification materials for the Forward Capacity Auction, as discussed in Section III.13.1 of Market Rule 1.

New Capacity Qualification Package is information submitted by certain new resources prior to participation in the Forward Capacity Auction, as described in Section III.13.1 of Market Rule 1.

New Capacity Resource is a resource (i) that never previously received any payment as a capacity resource including any capacity payment pursuant to the market rules in effect prior to June 1, 2010 and that has not cleared in any previous Forward Capacity Auction; or (ii) that is otherwise eligible to participate in the Forward Capacity Auction as a New Capacity Resource.

New Capacity Show of Interest Form is described in Section III.13.1.1.2.1 of Market Rule 1.

New Capacity Show of Interest Submission Window is the period of time during which a Project Sponsor may submit a New Capacity Show of Interest Form or a New Demand Capacity Resource Show of Interest Form, as described in Section III.13.1.10 of Market Rule 1.

New Demand Capacity Resource is a type of Demand Capacity Resource participating in the Forward Capacity Market, as defined in Section III.13.1.4.1 of Market Rule 1.

New Demand Capacity Resource Qualification Package is the information that a Project Sponsor must submit, in accordance with Section III.13.1.4.1.1.2 of Market Rule 1, for each resource that it seeks to offer in the Forward Capacity Auction as a New Demand Capacity Resource.

New Demand Capacity Resource Show of Interest Form is described in Section III.13.1.4.1.1.1 of Market Rule 1.

New England Control Area is the Control Area for New England, which includes PTF, Non-PTF, MTF and OTF. The New England Control Area covers Connecticut, Rhode Island, Massachusetts, New Hampshire, Vermont, and part of Maine (i.e., excluding the portions of Northern Maine and the northern portion of Eastern Maine which are in the Maritimes Control Area).

New England Markets are markets or programs for the purchase of energy, capacity, ancillary services, demand response services or other related products or services (including Financial Transmission Rights) that are delivered through or useful to the operation of the New England Transmission System and that are administered by the ISO pursuant to rules, rates, or agreements on file from time to time with the Federal Energy Regulatory Commission.

New England System Restoration Plan is the plan that is developed by ISO, in accordance with NERC Reliability Standards, NPCC regional criteria and standards, ISO New England Operating Documents and ISO operating agreements, to facilitate the restoration of the New England Transmission System following a partial or complete shutdown of the New England Transmission System.

New England Transmission System is the system of transmission facilities, including PTF, Non-PTF, OTF and MTF, within the New England Control Area under the ISO's operational jurisdiction.

New Generating Capacity Resource is a type of resource participating in the Forward Capacity Market, as described in Section III.13.1.1.1 of Market Rule 1.

New Import Capacity Resource is a type of resource participating in the Forward Capacity Market, as defined in Section III.13.1.3.4 of Market Rule 1.

New Resource Offer Floor Price is defined in Section III.A.21.2.

NMPTC means Non-Market Participant Transmission Customer.

NMPTC Credit Threshold is described in Section V.A.2 of the ISO New England Financial Assurance Policy.

NMPTC Financial Assurance Requirement is an amount of additional financial assurance for Non-Market Participant Transmission Customers described in Section V.D of the ISO New England Financial Assurance Policy.

Node is a point on the New England Transmission System at which LMPs are calculated.

No-Load Fee is the amount, in dollars per hour, for a Generator Asset that must be paid to Market Participants with an Ownership Share in the Generator Asset for being scheduled in the New England Markets, in addition to the Start-Up Fee and price offered to supply energy, for each hour that the Generator Asset is scheduled in the New England Markets.

Nominated Consumption Limit is the consumption level specified by the Market Participant for a Dispatchable Asset Related Demand as adjusted in accordance with the provisions of Section III.13.7.5.1.3.

Non-Commercial Capacity is the capacity of a New Capacity Resource or an Existing Capacity Resource, or portion thereof, that has not achieved FCM Commercial Operation.

Non-Commercial Capacity Cure Period is the time period described in Section VII.D of the ISO New England Financial Assurance Policy.

Non-Commercial Capacity Financial Assurance Amount (Non-Commercial Capacity FA Amount) is the financial assurance amount held on Non-Commercial Capacity cleared in a Forward Capacity Auction as calculated in accordance with Section VII.B.2 of the ISO New England Financial Assurance Policy.

Non-Designated Blackstart Resource Study Cost Payments are the study costs reimbursed under Section 5.3 of Schedule 16 of the OATT.

Non-Dispatchable Resource is any Resource that does not meet the requirements to be a Dispatchable Resource.

Non-Hourly Charges are defined in Section 1.3 of the ISO New England Billing Policy.

Non-Hourly Requirements are determined in accordance with Section III.A(ii) of the ISO New England Financial Assurance Policy, which is Exhibit 1A of Section I of the Tariff.

Non-Incumbent Transmission Developer is a Qualified Transmission Project Sponsor that: (i) is not currently a PTO; (ii) has a transmission project listed in the RSP Project List; and (iii) has executed a Non-Incumbent Transmission Developer Operating Agreement. "Non-Incumbent Transmission Developer" also includes a PTO that proposes the development of a transmission facility not located within or connected to its existing electric system; however, because such a PTO is a party to the TOA, it is not required to enter into a Non-Incumbent Transmission Developer Operating Agreement.

Non-Incumbent Transmission Developer Operating Agreement (or NTDOA) is an agreement between the ISO and a Non-Incumbent Transmission Developer in the form specified in Attachment O to the OATT that sets forth their respective rights and responsibilities to each other with regard to proposals for and construction of certain transmission facilities.

Non-Market Participant is any entity that is not a Market Participant.

Non-Market Participant Transmission Customer is any entity which is not a Market Participant but is a Transmission Customer.

Non-Municipal Market Participant is defined in Section II of the ISO New England Financial Assurance Policy.

Non-PTF Transmission Facilities (Non-PTF) are the transmission facilities owned by the PTOs that do not constitute PTF, OTF or MTF.

Non-Qualifying means a Market Participant that is not a Credit Qualifying Market Participant.

Notice of RBA is defined in Section 6.3.2 of the ISO New England Billing Policy.

Notification Time is the time required for a Generator Asset to synchronize to the system from the time a startup Dispatch Instruction is received from the ISO.

Northeastern Planning Protocol is the Amended and Restated Northeastern ISO/RTO Planning Coordination Protocol on file with the Commission and posted on the ISO website at the following URL: www.iso-ne.com/static-assets/documents/2015/07/northeastern_protocol_dmeast.doc.

NPCC is the Northeast Power Coordinating Council.

Obligation Month means a time period of one calendar month for which capacity payments are issued and the costs associated with capacity payments are allocated.

Offer Data means the scheduling, operations planning, dispatch, new Resource, and other data, including Generator Asset, Dispatchable Asset Related Demand, and Demand Response Resource operating limits based on physical characteristics, and information necessary to schedule and dispatch Generator Assets, Dispatchable Asset Related Demands, and Demand Response Resources for the provision or consumption of energy, the provision of other services, and the maintenance of the reliability and security of the transmission system in the New England Control Area, and specified for submission to the New England Markets for such purposes by the ISO.

Offered CLAIM10 is a Supply Offer value or a Demand Reduction Offer value between 0 and the CLAIM10 of the resource that represents the amount of TMNSR available either from an off-line Fast Start Generator or from a Fast Start Demand Response Resource that has not been dispatched.

Offered CLAIM30 is a Supply Offer value or a Demand Reduction Offer value between 0 and the CLAIM30 of the resource that represents the amount of TMOR available either from an off-line Fast Start Generator or from a Fast Start Demand Response Resource that has not been dispatched.

On-Peak Demand Resource is a type of Demand Capacity Resource and means installed measures (e.g., products, equipment, systems, services, practices and/or strategies) on end-use customer facilities that reduce the total amount of electrical energy consumed during Demand Resource On-Peak Hours, while delivering a comparable or acceptable level of end-use service. Such measures include Energy Efficiency, Load Management, and Distributed Generation.

Open Access Same-Time Information System (OASIS) is the ISO information system and standards of conduct responding to requirements of 18 C.F.R. §37 of the Commission's regulations and all additional requirements implemented by subsequent Commission orders dealing with OASIS.

Open Access Transmission Tariff (OATT) is Section II of the ISO New England Inc. Transmission, Markets and Services Tariff.

Operating Authority is defined pursuant to a MTOA, an OTOA, the TOA or the OATT, as applicable.

Operating Data means GADS Data, data equivalent to GADS Data, CARL Data, metered load data, or actual system failure occurrences data, all as described in the ISO New England Operating Procedures.

Operating Day means the calendar day period beginning at midnight for which transactions on the New England Markets are scheduled.

Operating Reserve means Ten-Minute Spinning Reserve (TMSR), Ten-Minute Non-Spinning Reserve (TMNSR) and Thirty-Minute Operating Reserve (TMOR).

Operations Date is February 1, 2005.

OTF Service is transmission service over OTF as provided for in Schedule 20.

Other Transmission Facility (OTF) are the transmission facilities owned by Transmission Owners, defined and classified as OTF pursuant to Schedule 20, over which the ISO shall exercise Operating

Authority in accordance with the terms set forth in the OTOA, rated 69 kV or above, and required to allow energy from significant power sources to move freely on the New England Transmission System. OTF classification shall be limited to the Phase I/II HVDC-TF.

Other Transmission Operating Agreements (OTOA) is the agreement(s) between the ISO, an OTO and/or the associated service provider(s) with respect to an OTF, which includes the HVDC Transmission Operating Agreement and the Phase I/II HVDC-TF Transmission Service Administration Agreement. With respect to the Phase I/II HVDC-TF, the HVDC Transmission Operating Agreement covers the rights and responsibilities for the operation of the facility and the Phase I/II HVDC-TF Transmission Service Administration Agreement covers the rights and responsibilities for the administration of transmission service.

Other Transmission Owner (OTO) is an owner of OTF.

Ownership Share is a right or obligation, for purposes of settlement, to a percentage share of all credits or charges associated with a Generator Asset or a Load Asset, where such facility is interconnected to the New England Transmission System.

Participant Expenses are defined in Section 1 of the Participants Agreement.

Participant Required Balance is defined in Section 5.3 of the ISO New England Billing Policy.

Participant Vote is defined in Section 1 of the Participants Agreement.

Participants Agreement is the agreement among the ISO, the New England Power Pool and Individual Participants, as amended from time to time, on file with the Commission.

Participants Committee is the principal committee referred to in the Participants Agreement.

Participating Transmission Owner (PTO) is a transmission owner that is a party to the TOA.

Passive DR Audit is the audit performed pursuant to Section III.13.6.1.5.4.

Passive DR Auditing Period is the summer Passive DR Auditing Period (June 1 to August 31) or winter Passive DR Auditing Period (December 1 to January 31) applicable to On-Peak Demand Resources and Seasonal Peak Demand Resources.

Payment is a sum of money due to a Covered Entity from the ISO.

Payment Default Shortfall Fund is defined in Section 5.1 of the ISO New England Billing Policy.

Peak Energy Rent (PER) is described in Section III.13.7.1.2 of Market Rule 1.

PER Proxy Unit is described in Section III.13.7.1.2.1 of Market Rule 1.

Permanent De-list Bid is a bid that may be submitted by an Existing Generating Capacity Resource, Existing Import Capacity Resource, or Existing Demand Capacity Resource in the Forward Capacity Auction to permanently remove itself from the capacity market, as described in Section III.13.1.2.3.1.5 of Market Rule 1.

Phase I Transfer Credit is 40% of the HQICC, or such other fraction of the HQICC as the ISO may establish.

Phase I/II HVDC-TF is defined in Schedule 20A to Section II of this Tariff.

Phase I/II HVDC-TF Transfer Capability is the transfer capacity of the Phase I/II HVDC-TF under normal operating conditions, as determined in accordance with Good Utility Practice. The "Phase I Transfer Capability" is the transfer capacity under normal operating conditions, as determined in accordance with Good Utility Practice, of the Phase I terminal facilities as determined initially as of the time immediately prior to Phase II of the Phase I/II HVDC-TF first being placed in service, and as adjusted thereafter only to take into account changes in the transfer capacity which are independent of any effect of Phase II on the operation of Phase I. The "Phase II Transfer Capability" is the difference between the Phase I/II HVDC-TF Transfer Capability and the Phase I Transfer Capability. Determinations of, and any adjustment in, Phase I/II HVDC-TF Transfer Capability shall be made by the ISO, and the basis for any such adjustment shall be explained in writing and posted on the ISO website.

Phase One Proposal is a first round submission, as defined in Section 4.3 of Attachment K of the OATT, of a proposal for a Reliability Transmission Upgrade or Market Efficiency Transmission Upgrade, as applicable, by a Qualified Transmission Project Sponsor.

Phase II Transfer Credit is 60% of the HQICC, or such other fraction of the HQICC as the ISO may establish.

Phase Two Solution is a second round submission, as defined in Section 4.3 of Attachment K of the OATT, of a proposal for a Reliability Transmission Upgrade or Market Efficiency Transmission Upgrade by a Qualified Transmission Project Sponsor.

Planning Advisory Committee is the committee described in Attachment K of the OATT.

Planning and Reliability Criteria is defined in Section 3.3 of Attachment K to the OATT.

Planning Authority is an entity defined as such by the North American Electric Reliability Corporation.

Point(s) of Delivery (POD) is point(s) of interconnection where capacity and/or energy transmitted by a Transmission Customer will be made available to the Receiving Party under the OATT.

Point of Interconnection shall have the same meaning as that used for purposes of Schedules 22, 23 and 25 of the OATT.

Point(s) of Receipt (POR) is point(s) of interconnection where capacity and/or energy transmitted by a Transmission Customer will be made available by the Delivering Party under the OATT.

Point-To-Point Service is the transmission of capacity and/or energy on either a firm or non-firm basis from the Point(s) of Receipt to the Point(s) of Delivery under the OATT pursuant to Local Point-To-Point Service or OTF Service or MTF Service; and the transmission of capacity and/or energy from the Point(s) of Receipt to the Point(s) of Delivery under the OATT pursuant to Through or Out Service.

Pool-Planned Unit is one of the following units: New Haven Harbor Unit 1 (Coke Works), Mystic Unit 7, Canal Unit 2, Potter Unit 2, Wyman Unit 4, Stony Brook Units 1, 1A, 1B, 1C, 2A and 2B, Millstone

Unit 3, Seabrook Unit 1 and Waters River Unit 2 (to the extent of 7 megawatts of its Summer capability and 12 megawatts of its Winter capability).

Pool PTF Rate is the transmission rate determined in accordance with Schedule 8 to the OATT.

Pool RNS Rate is the transmission rate determined in accordance with paragraph (2) of Schedule 9 of Section II of the Tariff.

Pool-Scheduled Resources are described in Section III.1.10.2 of Market Rule 1.

Pool Supported PTF is defined as: (i) PTF first placed in service prior to January 1, 2000; (ii) Generator Interconnection Related Upgrades with respect to Category A and B projects (as defined in Schedule 11), but only to the extent not paid for by the interconnecting Generator Owner; and (iii) other PTF upgrades, but only to the extent the costs therefore are determined to be Pool Supported PTF in accordance with Schedule 12.

Pool Transmission Facility (PTF) means the transmission facilities owned by PTOs which meet the criteria specified in Section II.49 of the OATT.

Posting Entity is any Market Participant or Non-Market Participant Transmission Customer providing financial security under the provisions of the ISO New England Financial Assurance Policy.

Posture means an action of the ISO to deviate from the jointly optimized security constrained economic dispatch for Energy and Operating Reserves solution for a Resource produced by the ISO's technical software for the purpose of maintaining sufficient Operating Reserve (both online and off-line) or for the provision of voltage or VAR support.

Posturing Credits are the Real-Time Posturing NCPC Credits for Generators (Other Than Limited Energy Resources) Postured for Reliability and the Real-Time Posturing NCPC Credit for Limited Energy Resources Postured for Reliability.

Power Purchaser is the entity that is purchasing the capacity and/or energy to be transmitted under the OATT.

Principal is (i) the sole proprietor of a sole proprietorship; (ii) a general partner of a partnership; (iii) a president, chief executive officer, chief operating officer or chief financial officer (or equivalent position) of an organization; (iv) a manager, managing member or a member vested with the management authority for a limited liability company or limited liability partnership; (v) any person or entity that has the power to exercise a controlling influence over an organization's activities that are subject to regulation by the Federal Energy Regulatory Commission, the Securities and Exchange Commission, the Commodity Futures Trading Commission, any exchange monitored by the National Futures Association, or any state entity responsible for regulating activity in energy markets; or (vi) any person or entity that: (a) is the direct owner of 10% or more of any class of an organization's equity securities; or (b) has directly contributed 10% or more of an organization's capital.

Profiled Load Assets include all Load Assets that are not directly metered by OP-18 compliant metering as currently described in Section IV (Metering and Recording for Settlements) of OP18, and some Load Assets that are measured by OP-18 compliant metering (as currently described in Section IV of OP-18) to which the Host Participant Assigned Meter Reader allocates non-PTF losses.

Project Sponsor is an entity seeking to have a New Generating Capacity Resource, New Import Capacity Resource or New Demand Capacity Resource participate in the Forward Capacity Market, as described in Section III.13.

Proxy De-List Bid is a type of bid used in the Forward Capacity Market.

Provisional Member is defined in Section I.68A of the Restated NEPOOL Agreement.

PTO Administrative Committee is the committee referred to in Section 11.04 of the TOA.

Public Policy Requirement is a requirement reflected in a statute enacted by, or a regulation promulgated by, the federal government or a state or local (e.g., municipal or county) government.

Public Policy Transmission Study is a study conducted by the ISO pursuant to the process set out in Section 4A.3 of Attachment K of the OATT, and consists of two phases: (i) an initial phase to produce a rough estimate of the costs and benefits of concepts that could meet transmission needs driven by public policy requirements; and (ii) a follow-on phase designed to produce more detailed analysis and engineering work on transmission concepts identified in the first phase.

Public Policy Local Transmission Study is a study conducted by a PTO pursuant to the process set out in Section 1.6 of Attachment K Appendix 1 of the OATT, and consists of two phases: (i) an initial phase to produce an estimate of the costs and benefits of concepts that could meet transmission needs driven by public policy requirements; and (ii) a follow-on phase designed to produce more detailed analysis and engineering work on transmission concepts identified in the first phase.

Public Policy Transmission Upgrade is an addition and/or upgrade to the New England Transmission System that meets the voltage and non-voltage criteria for Public Policy Transmission Upgrade PTF classification specified in the OATT, and has been included in the Regional System Plan and RSP Project List as a Public Policy Transmission Upgrade pursuant to the procedures described in Section 4A of Attachment K of the OATT.

Publicly Owned Entity is defined in Section I of the Restated NEPOOL Agreement.

Qualification Process Cost Reimbursement Deposit is described in Section III.13.1.9.3 of Market Rule 1.

Qualified Capacity is the amount of capacity a resource may provide in the summer or winter in a Capacity Commitment Period, as determined in the Forward Capacity Market qualification processes.

Qualified Generator Reactive Resource(s) is any generator source of dynamic reactive power that meets the criteria specified in Schedule 2 of the OATT.

Qualified Non-Generator Reactive Resource(s) is any non-generator source of dynamic reactive power that meets the criteria specified in Schedule 2 of the OATT.

Qualified Reactive Resource(s) is any Qualified Generator Reactive Resource and/or Qualified Non-Generator Reactive Resource that meets the criteria specified in Schedule 2 of the OATT.

Qualified Transmission Project Sponsor is defined in Sections 4B.2 and 4B.3 of Attachment K of the OATT.

Queue Position has the meaning specified in Section I of Schedule 22, Attachment 1 to Schedule 23, and Section I of Schedule 25 of the OATT.

Rapid Response Pricing Asset is: (i) a Fast Start Generator; (ii) a Flexible DNE Dispatchable Generator; or (iii) a Binary Storage DARD with Offer Data specifying a Minimum Run Time and a Minimum Down Time not exceeding one hour each. A Rapid Response Pricing Asset shall also include a Fast Start Demand Response Resource for which the Market Participant's Offer Data meets the following criteria: (i) Minimum Reduction Time does not exceed one hour; and (ii) Demand Response Resource Notification Time plus Demand Response Resource Start-Up Time does not exceed 30 minutes.

Rapid Response Pricing Opportunity Cost is the NCPC Credit described in Section III.F.2.3.10.

Rated means a Market Participant that receives a credit rating from one or more of the Rating Agencies, or, if such Market Participant is not rated by one of the Rating Agencies, then a Market Participant that has outstanding unsecured debt rated by one or more of the Rating Agencies.

Rating Agencies are Standard and Poor's (S&P), Moody's, and Fitch.

Rationing Minimum Limit is the MW quantity for a New Generating Capacity Resource or Existing Generating Capacity Resource below which n offer or bid may not be rationed in the Forward Capacity Auction, but shall not apply to supply offers or demand bids in a substitution auction as specified in Section III.13.2.8.2 and Section III.13.2.8.3.

RBA Decision is a written decision provided by the ISO to a Disputing Party and to the Chair of the NEPOOL Budget and Finance Subcommittee accepting or denying a Requested Billing Adjustment within twenty Business Days of the date the ISO distributes a Notice of RBA, unless some later date is agreed upon by the Disputing Party and the ISO.

Reactive Capability Audit is an audit that measures the ability of a Reactive Resource to provide or absorb reactive power to or from the transmission system at a specified real power output or consumption.

Reactive Resource is a device that dynamically adjusts reactive power output automatically in Real-Time over a continuous range, taking into account control system response bandwidth, within a specified voltage bandwidth in response to grid voltage changes. These resources operate to maintain a set-point

voltage and include, but are not limited to, Generator Assets, Dispatchable Asset Related Demands that are part of an Electric Storage Facility, and dynamic transmission devices.

Reactive Supply and Voltage Control Service is the form of Ancillary Service described in Schedule 2 of the OATT.

Real-Time is a period in the current Operating Day for which the ISO dispatches Resources for energy and Regulation, designates Resources for Regulation and Operating Reserve and, if necessary, commits additional Resources.

Real-Time Adjusted Load Obligation is defined in Section III.3.2.1(b) of Market Rule 1.

Real-Time Adjusted Load Obligation Deviation is defined in Section III.3.2.1(d) of Market Rule 1.

Real-Time Commitment NCPC Credit is an NCPC Credit calculated pursuant to Appendix F to Market Rule 1.

Real-Time Congestion Revenue is defined in Section III.3.2.1(i) of Market Rule 1.

Real-Time Demand Reduction Obligation is defined in Section III.3.2.1(c) of Market Rule 1.

Real-Time Demand Reduction Obligation Deviation is defined in Section III.3.2.1(e) of Market Rule 1.

Real-Time Dispatch NCPC Credit is an NCPC Credit calculated pursuant to Appendix F to Market Rule 1.

Real-Time Energy Inventory is a component of the spot payment that a Market Participant may receive through the inventoried energy program, as described in Section III.K.3.2.1 of Market Rule 1.

Real-Time Energy Market means the purchase or sale of energy, purchase of demand reductions, payment of Congestion Costs, and payment for losses for quantity deviations from the Day-Ahead Energy Market in the Operating Day and designation of and payment for provision of Operating Reserve in Real-Time.

Real-Time Energy Market Deviation Congestion Charge/Credit is defined in Section III.3.2.1(g) of Market Rule 1.

Real-Time Energy Market Deviation Energy Charge/Credit is defined in Section III.3.2.1(g) of Market Rule 1.

Real-Time Energy Market Deviation Loss Charge/Credit is defined in Section III.3.2.1(g) of Market Rule 1.

Real-Time Energy Market NCPC Credits are the Real-Time Commitment NCPC Credit and the Real-Time Dispatch NCPC Credit.

Real-Time External Transaction NCPC Credit is an NCPC Credit calculated pursuant to Appendix F to Market Rule 1.

Real-Time Generation Obligation is defined in Section III.3.2.1(b) of Market Rule 1.

Real-Time Generation Obligation Deviation is defined in Section III.3.2.1(d) of Market Rule 1.

Real-Time High Operating Limit is the maximum output, in MW, of a Generator Asset that could be achieved, consistent with Good Utility Practice, in response to an ISO request for Energy (including pursuant to Section III.13.6.4 of Market Rule 1), for each hour of the Operating Day, as reflected in the Generator Asset's Offer Data. This value is based on real-time operating conditions and the physical operating characteristics and operating permits of the facility and must be submitted for all Generator Assets (other than Settlement Only Resources).

Real-Time Load Obligation is defined in Section III.3.2.1(b) of Market Rule 1.

Real-Time Load Obligation Deviation is defined in Section III.3.2.1(d) of Market Rule 1.

Real-Time Locational Adjusted Net Interchange is defined in Section III.3.2.1(b) of Market Rule 1.

Real-Time Locational Adjusted Net Interchange Deviation is defined in Section III.3.2.1(d) of Market Rule 1.

Real-Time Loss Revenue is defined in Section III.3.2.1(l) of Market Rule 1.

Real-Time Loss Revenue Charges or Credits are defined in Section III.3.2.1(m) of Market Rule 1.

Real-Time NCP Load Obligation is the maximum hourly value, during a month, of a Market Participant's Real-Time Load Obligation summed over all Locations, excluding exports, in kilowatts.

Real-Time Offer Change is a modification to a Supply Offer pursuant to Section III.1.10.9(b).

Real-Time Posturing NCPC Credit for Generators (Other Than Limited Energy Resources) Postured for Reliability is an NCPC Credit calculated pursuant to Appendix F to Market Rule 1.

Real-Time Posturing NCPC Credit for Limited Energy Resources Postured for Reliability is an NCPC Credit calculated pursuant to Appendix F to Market Rule 1.

Real-Time Prices means the Locational Marginal Prices resulting from the ISO's dispatch of the New England Markets in the Operating Day.

Real-Time Reserve Charge is a Market Participant's share of applicable system and Reserve Zone Real-Time Operating Reserve costs attributable to meeting the Real-Time Operating Reserve requirement as calculated in accordance with Section III.10 of Market Rule 1.

Real-Time Reserve Clearing Price is the Real-Time TMSR, TMNSR or TMOR clearing price, as applicable, for the system and each Reserve Zone that is calculated in accordance with Section III.2.7A of Market Rule 1.

Real-Time Reserve Credit is a Market Participant's compensation associated with that Market Participant's Resources' Reserve Quantity For Settlement as calculated in accordance with Section III.10 of Market Rule 1.

Real-Time Reserve Designation is the amount, in MW, of Operating Reserve designated to a Resource in Real-Time by the ISO as described in Section III.1.7.19 of Market Rule 1.

Real-Time Reserve Opportunity Cost is defined in Section III.2.7A(b) of Market Rule 1.

Real-Time Synchronous Condensing NCPC Credit is an NCPC Credit calculated pursuant to Appendix F to Market Rule 1.

Real-Time System Adjusted Net Interchange means, for each hour, the sum of Real-Time Locational Adjusted Net Interchange for a Market Participant over all Locations, in kilowatts.

Receiving Party is the entity receiving the capacity and/or energy transmitted to Point(s) of Delivery under the OATT.

Reference Level is defined in Section III.A.5.7 of Appendix A of Market Rule 1.

Regional Benefit Upgrade(s) (RBU) means a Transmission Upgrade that: (i) is rated 115kV or above; (ii) meets all of the non-voltage criteria for PTF classification specified in the OATT; and (iii) is included in the Regional System Plan as either a Reliability Transmission Upgrade or a Market Efficiency Transmission Upgrade identified as needed pursuant to Attachment K of the OATT. The category of RBU shall not include any Transmission Upgrade that has been categorized under any of the other categories specified in Schedule 12 of the OATT (e.g., an Elective Transmission Upgrade shall not also be categorized as an RBU). Any upgrades to transmission facilities rated below 115kV that were PTF prior to January 1, 2004 shall remain classified as PTF and be categorized as an RBU if, and for so long as, such upgrades meet the criteria for PTF specified in the OATT.

Regional Network Load is the load that a Network Customer designates for Regional Network Service under Part II.B of the OATT. The Network Customer's Regional Network Load shall include all load designated by the Network Customer (including losses) and shall not be credited or reduced for any behind-the-meter generation. A Network Customer may elect to designate less than its total load as Regional Network Load but may not designate only part of the load at a discrete Point of Delivery. Where a Transmission Customer has elected not to designate a particular load at discrete Points of Delivery as Regional Network Load, the Transmission Customer is responsible for making separate arrangements

under Part II.C of the OATT for any Point-To-Point Service that may be necessary for such non-designated load.

Regional Network Service (RNS) is the transmission service over the PTF described in Part II.B of the OATT, including such service which is used with respect to Network Resources or Regional Network Load that is not physically interconnected with the PTF.

Regional Planning Dispute Resolution Process is described in Section 12 of Attachment K to the OATT.

Regional System Plan (RSP) is the plan developed under the process specified in Attachment K of the OATT.

Regional Transmission Service (RTS) is Regional Network Service and Through or Out Service as provided over the PTF in accordance with Section II.B, Section II.C, Schedule 8 and Schedule 9 of the OATT.

Regulation is the capability of a specific Resource with appropriate telecommunications, control and response capability to respond to an AGC SetPoint.

Regulation and Frequency Response Service is the form of Ancillary Service described in Schedule 3 of the OATT. The capability of performing Regulation and Frequency Response Service is referred to as automatic generation control (AGC).

Regulation Capacity is the lesser of five times the Automatic Response Rate and one-half of the difference between the Regulation High Limit and the Regulation Low Limit of a Resource capable of providing Regulation.

Regulation Capacity Requirement is the amount of Regulation Capacity required to maintain system control and reliability in the New England Control Area as calculated and posted on the ISO website.

Regulation Capacity Offer is an offer by a Market Participant to provide Regulation Capacity.

Regulation High Limit is an offer parameter that establishes the upper bound for AGC SetPoints and is used in the determination of a Resource's Regulation Capacity.

Regulation Low Limit is an offer parameter that establishes the lower bound for AGC SetPoints and is used in the determination of a Resource's Regulation Capacity.

Regulation Market is the market described in Section III.14 of Market Rule 1.

Regulation Resources are those Alternative Technology Regulation Resources and Generator Assets that satisfy the requirements of Section III.14.2. Regulation Resources are eligible to participate in the Regulation Market.

Regulation Service is the change in output or consumption made in response to changing AGC SetPoints.

Regulation Service Requirement is the estimated amount of Regulation Service required to maintain system control and reliability in the New England Control Area as calculated and posted on the ISO website.

Regulation Service Offer is an offer by a Market Participant to provide Regulation Service.

Related Person is defined pursuant to Section 1.1 of the Participants Agreement.

Related Transaction is defined in Section III.1.4.3 of Market Rule 1.

Reliability Administration Service (RAS) is the service provided by the ISO, as described in Schedule 3 of Section IV.A of the Tariff, in order to administer the Reliability Markets and provide other reliability-related and informational functions.

Reliability Committee is the committee whose responsibilities are specified in Section 8.2.3 of the Participants Agreement.

Reliability Markets are, collectively, the ISO's administration of Regulation, the Forward Capacity Market, and Operating Reserve.

Reliability Region means any one of the regions identified on the ISO's website. Reliability Regions are intended to reflect the operating characteristics of, and the major transmission constraints on, the New England Transmission System.

Reliability Transmission Upgrade means those additions and upgrades not required by the interconnection of a generator that are nonetheless necessary to ensure the continued reliability of the New England Transmission System, taking into account load growth and known resource changes, and include those upgrades necessary to provide acceptable stability response, short circuit capability and system voltage levels, and those facilities required to provide adequate thermal capability and local voltage levels that cannot otherwise be achieved with reasonable assumptions for certain amounts of generation being unavailable (due to maintenance or forced outages) for purposes of long-term planning studies. Good Utility Practice, applicable reliability principles, guidelines, criteria, rules, procedures and standards of ERO and NPCC and any of their successors, applicable publicly available local reliability criteria, and the ISO System Rules, as they may be amended from time to time, will be used to define the system facilities required to maintain reliability in evaluating proposed Reliability Transmission Upgrades. A Reliability Transmission Upgrade may provide market efficiency benefits as well as reliability benefits to the New England Transmission System.

Remittance Advice is an issuance from the ISO for the net Payment owed to a Covered Entity where a Covered Entity's total Payments exceed its total Charges in a billing period.

Remittance Advice Date is the day on which the ISO issues a Remittance Advice.

Renewable Technology Resource is a Generating Capacity Resource or an On-Peak Demand Resource that satisfies the requirements specified in Section III.13.1.1.1.7.

Re-Offer Period is the period that normally occurs between the posting of the of the Day-Ahead Energy Market results and 2:00 p.m. on the day before the Operating Day during which a Market Participant may submit revised Supply Offers, revised External Transactions, or revised Demand Bids associated with Dispatchable Asset Related Demands or, revised Demand Reduction Offers associated with Demand Response Resources.

Replacement Reserve is described in Part III, Section VII of ISO New England Operating Procedure No. 8.

Request for Alternative Proposals (RFAP) is the request described in Attachment K of the OATT.

Requested Billing Adjustment (RBA) is defined in Section 6.1 of the ISO New England Billing Policy.

Required Balance is an amount as defined in Section 5.3 of the Billing Policy.

Reseller is a MGTSA holder that sells, assigns or transfers its rights under its MGTSA, as described in Section II.45.1(a) of the OATT.

Reserve Adequacy Analysis is the analysis performed by the ISO to determine if adequate Resources are committed to meet forecasted load, Operating Reserve, and security constraint requirements for the current and next Operating Day.

Reserve Constraint Penalty Factors (RCPFs) are rates, in $/MWh, that are used within the Real-Time dispatch and pricing algorithm to reflect the value of Operating Reserve shortages and are defined in Section III.2.7A(c) of Market Rule 1; and, commencing on June 1, 2024, that are used within the Day-Ahead Energy Market security-constrained economic commitment and dispatch process to reflect the value of Day-Ahead Ancillary Services shortages and forecast energy requirement shortages and are defined in Section III.2.6.2(b) of Market Rule 1.

Reserve Quantity For Settlement is defined in Section III.10.1 of Market Rule 1.

Reserve Zone is defined in Section III.2.7 of Market Rule 1.

Reserved Capacity is the maximum amount of capacity and energy that is committed to the Transmission Customer for transmission over the New England Transmission System between the Point(s) of Receipt and the Point(s) of Delivery under Part II.C or Schedule 18, 20 or 21 of the OATT, as applicable. Reserved Capacity shall be expressed in terms of whole kilowatts on a sixty-minute interval (commencing on the clock hour) basis, or, in the case of Reserved Capacity for Local Point-to-Point Service, in terms of whole megawatts on a sixty-minute interval basis.

Resource means a Generator Asset, a Dispatchable Asset Related Demand, an External Resource, an External Transaction, or a Demand Response Resource.

Restated New England Power Pool Agreement (RNA) is the Second Restated New England Power Pool Agreement, which restated for a second time by an amendment dated as of August 16, 2004 the New England Power Pool Agreement dated September 1, 1971, as the same may be amended and restated from time to time, governing the relationship among the NEPOOL members.

Rest-of-Pool Capacity Zone is a single Capacity Zone made up of the adjacent Load Zones that are neither export-constrained nor import-constrained.

Rest of System is an area established under Section III.2.7(d) of Market Rule 1.

Retail Delivery Point is the point on the transmission or distribution system at which the load of an end-use facility, which is metered and assigned a unique account number by the Host Participant, is measured to determine the amount of energy delivered to the facility from the transmission and distribution system. If an end-use facility is connected to the transmission or distribution system at more than one location, the Retail Delivery Point shall consist of the metered load at each connection point, summed to measure the net energy delivered to the facility in each interval.

Retirement De-List Bid is a bid to retire an Existing Generating Capacity Resource, Existing Import Capacity Resource, or Existing Demand Capacity Resource from all New England Markets, as described in Section III.13.1.2.3.1.5.

Returning Market Participant is a Market Participant, other than an FTR-Only Customer or a Governance Only Member, whose previous membership as a Market Participant was involuntarily terminated due to a Financial Assurance Default or a payment default and, since returning, has been a Market Participant for less than six consecutive months.

Revenue Requirement is defined in Section IV.A.2.1 of the Tariff.

Reviewable Action is defined in Section III.D.1.1 of Appendix D of Market Rule 1.

Reviewable Determination is defined in Section 12.4(a) of Attachment K to the OATT.

RSP Project List is defined in Section 1 of Attachment K to the OATT.

RTEP02 Upgrade(s) means a Transmission Upgrade that was included in the annual NEPOOL Transmission Plan (also known as the "Regional Transmission Expansion Plan" or "RTEP") for the year 2002, as approved by ISO New England Inc.'s Board of Directors, or the functional equivalent of such Transmission Upgrade, as determined by ISO New England Inc. The RTEP02 Upgrades are listed in Schedule 12B of the OATT.

RTO is a regional transmission organization or comparable independent transmission organization that complies with Order No. 2000 and the Commission's corresponding regulation.

Same Reserve Zone Export Transaction is defined in Section III.1.10.7(f)(iii) of Market Rule 1.

Sanctionable Behavior is defined in Section III.B.3 of Appendix B of Market Rule 1.

Schedule, Schedules, Schedule 1, 2, 3, 4 and 5 are references to the individual or collective schedules to Section IV.A. of the Tariff.

Schedule 20A Service Provider (SSP) is defined in Schedule 20A to Section II of this Tariff.

Scheduling Service, for purposes of Section IV.A and Section IV.B of the Tariff, is the service described in Schedule 1 to Section IV.A of the Tariff.

Scheduling, System Control and Dispatch Service, for purposes of Section II of the Tariff, is the form of Ancillary Service described in Schedule 1 of the OATT.

Seasonal Claimed Capability is the summer or winter claimed capability of a Generator Asset or Generating Capacity Resource, and represents the maximum dependable load carrying ability of the asset or resource, excluding capacity required for station use.

Seasonal Claimed Capability Audit is the Generator Asset audit performed pursuant to Section III.1.5.1.3.

Seasonal DR Audit is the Demand Response Resource audit performed pursuant to Section III.1.5.1.3.1.

Seasonal Peak Demand Resource is a type of Demand Capacity Resource and shall mean installed measures (e.g., products, equipment, systems, services, practices and/or strategies) on end-use customer facilities that reduce the total amount of electrical energy consumed during Demand Resource Seasonal Peak Hours, while delivering a comparable or acceptable level of end-use service. Such measures include Energy Efficiency, Load Management, and Distributed Generation.

Section III.1.4 Transactions are defined in Section III.1.4.2 of Market Rule 1.

Section III.1.4 Conforming Transactions are defined in Section III.1.4.2 of Market Rule 1.

Security Agreement is Attachment 1 to the ISO New England Financial Assurance Policy.

Selected Qualified Transmission Project Sponsor is the Qualified Transmission Project Sponsor that proposed the Phase Two or Stage Two Solution that has been identified by the ISO as the preferred Phase Two or Stage Two Solution.

Selected Qualified Transmission Project Sponsor Agreement is the agreement between the ISO and a Selected Qualified Transmission Project Sponsor. The Selected Qualified Transmission Project Sponsor Agreement is provided in Attachment P to the OATT.

Self-Schedule is the action of a Market Participant in committing its Generator Asset or DARD, in accordance with applicable ISO New England Manuals, to provide service in an hour, whether or not in the absence of that action the Generator Asset or DARD would have been committed by the ISO to provide the service. For a Generator Asset, Self-Schedule is the action of a Market Participant in committing a Generator Asset to provide Energy in an hour at its Economic Minimum Limit, whether or not in the absence of that action the Generator Asset would have been committed by the ISO to provide the Energy. For a DARD, Self-Schedule is the action of a Market Participant in committing a DARD to consume Energy in an hour at its Minimum Consumption Limit, whether or not in the absence of that action the DARD would have been committed by the ISO to consume Energy. For an External Transaction, a Self-Schedule is a request by a Market Participant for the ISO to select the External Transaction regardless of the LMP. Demand Response Resources are not permitted to Self-Schedule.

Self-Supplied FCA Resource is described in Section III.13.1.6 of Market Rule 1.

Senior Officer means an officer of the subject entity with the title of vice president (or similar office) or higher, or another officer designated in writing to the ISO by that office.

Service Agreement is a Transmission Service Agreement or an MPSA.

Service Commencement Date is the date service is to begin pursuant to the terms of an executed Service Agreement, or the date service begins in accordance with the sections of the OATT addressing the filing of unexecuted Service Agreements.

Services means, collectively, the Scheduling Service, EAS and RAS; individually, a Service.

Settlement Financial Assurance is an amount of financial assurance required from a Designated FTR Participant awarded a bid in an FTR Auction. This amount is calculated pursuant to Section VI.C of the ISO New England Financial Assurance Policy.

Settlement Only Resources are generators of less than 5 MW or otherwise eligible for Settlement Only Resource treatment as described in ISO New England Operating Procedure No. 14 and that have elected Settlement Only Resource treatment as described in the ISO New England Manual for Registration and Performance Auditing.

Shortfall Funding Arrangement, as specified in Section 5.1 of the ISO New England Billing Policy, is a separate financing arrangement that can be used to make up any non-congestion related differences between amounts received on Invoices and amounts due for ISO Charges in any bill issued.

Short-Term is a period of less than one year.

Significantly Reduced Congestion Costs are defined in Section III.G.2.2 of Appendix G to Market Rule 1.

SMD Effective Date is March 1, 2003.

Solutions Study is described in Section 4.2(b) of Attachment K to the OATT.

Special Constraint Resource (SCR) is a Resource that provides Special Constraint Resource Service under Schedule 19 of the OATT.

Special Constraint Resource Service is the form of Ancillary Service described in Schedule 19 of the OATT.

Specified-Term Blackstart Capital Payment is the annual compensation level, as calculated pursuant to Section 5.1 of Schedule 16 of the OATT, for a Designated Blackstart Resource's capital Blackstart Equipment costs associated with the provision of Blackstart Service (except for capital costs associated with adhering to NERC Critical Infrastructure Protection Reliability Standards as part of Blackstart Service).

Sponsored Policy Resource is a New Capacity Resource that: receives an out-of-market revenue source supported by a government-regulated rate, charge or other regulated cost recovery mechanism, and; qualifies as a renewable, clean or alternative energy resource under a renewable energy portfolio standard, clean energy standard, alternative energy portfolio standard, renewable energy goal, or clean energy goal enacted (either by statute or regulation) in the New England state from which the resource receives the out-of-market revenue source and that is in effect on January 1, 2018.

Stage One Proposal is a first round submission, as defined in Sections 4A.5 of Attachment K of the OATT, of a proposal for a Public Policy Transmission Upgrade by a Qualified Transmission Project Sponsor.

Stage Two Solution is a second round submission, as defined in Section 4A.5 of Attachment K of the OATT, of a proposal for a Public Policy Transmission Upgrade by a Qualified Transmission Project Sponsor.

Standard Blackstart Capital Payment is the annual compensation level, as calculated pursuant to Section 5.1 of Schedule 16 of the OATT, for a Designated Blackstart Resource's capital Blackstart Equipment costs associated with the provision of Blackstart Service (except for capital costs associated with adhering to NERC Critical Infrastructure Protection Reliability Standards as part of Blackstart Service).

Start-of-Round Price is the highest price associated with a round of a Forward Capacity Auction as described in Section III.13.2.3.1 of Market Rule 1.

Start-Up Fee is the amount, in dollars, that must be paid for a Generator Asset to Market Participants with an Ownership Share in the Generator Asset each time the Generator Asset is scheduled in the New England Markets to start-up.

Start-Up Time is the time it takes the Generator Asset, after synchronizing to the system, to reach its Economic Minimum Limit and, for dispatchable Generator Assets, be ready for further dispatch by the ISO.

State Estimator means the computer model of power flows specified in Section III.2.3 of Market Rule 1.

Statements, for the purpose of the ISO New England Billing Policy, refer to both Invoices and Remittance Advices.

Static De-List Bid is a bid that may be submitted by an Existing Generating Capacity Resource, Existing Import Capacity Resource, or Existing Demand Capacity Resource in the Forward Capacity Auction to remove itself from the capacity market for a one year period, as described in Section III.13.1.2.3.1.1 of Market Rule 1.

Station is one or more Existing Generating Capacity Resources consisting of one or more assets located within a common property boundary.

Station Going Forward Common Costs are the net costs associated with a Station that are avoided only by the clearing of the Static De-List Bids, the Permanent De-List Bids or the Retirement De-List Bids of all the Existing Generating Capacity Resources comprising the Station.

Station-level Blackstart O&M Payment is defined and calculated as specified in Section 5.1.2 of Schedule 16 to the OATT.

Station-level Specified-Term Blackstart Capital Payment is defined and calculated as specified in Section 5.1.2 of Schedule 16 to the OATT.

Station-level Standard Blackstart Capital Payment is defined and calculated as specified in Section 5.1.2 of Schedule 16 to the OATT.

Storage DARD is a DARD that participates in the New England Markets as part of an Electric Storage Facility, as described in Section III.1.10.6 of Market Rule 1.

Summer ARA Qualified Capacity is described in Section III.13.4.2.1.2.1.1.1 of Market Rule 1.

Summer Capability Period means one of two time periods defined by the ISO for the purposes of rating and auditing resources pursuant to Section III.9. The time period associated with the Summer Capability Period is the period of June 1 through September 30.

Summer Intermittent Reliability Hours are defined in Section III.13.1.2.2.2.1(c) of Market Rule 1.

Supply Offer is a proposal to furnish energy at a Node or Regulation from a Resource that meets the applicable requirements set forth in the ISO New England Manuals submitted to the ISO by a Market Participant with authority to submit a Supply Offer for the Resource. The Supply Offer will be submitted pursuant to Market Rule 1 and applicable ISO New England Manuals, and include a price and information with respect to the quantity proposed to be furnished, technical parameters for the Resource, timing and other matters. A Supply Offer is a subset of the information required in a Market Participant's Offer Data.

Supply Offer Block-Hours are Block-Hours assigned to the Lead Market Participant for each Supply Offer. Blocks of the Supply Offer in effect for each hour will be totaled to determine the quantity of Supply Offer Block-Hours for a given day. In the case that a Resource has a Real-Time unit status of "unavailable" for the entire day, that day will not contribute to the quantity of Supply Offer Block-Hours. However, if the Resource has at least one hour of the day with a unit status of "available," the entire day will contribute to the quantity of Supply Offer Block-Hours.

Synchronous Condenser is a generator that is synchronized to the grid but supplying no energy for the purpose of providing Operating Reserve or VAR or voltage support.

System Condition is a specified condition on the New England Transmission System or on a neighboring system, such as a constrained transmission element or flowgate, that may trigger Curtailment of Long-

Term Firm MTF or OTF Service on the MTF or the OTF using the curtailment priority pursuant to Section II.44 of the Tariff or Curtailment of Local Long-Term Firm Point-to-Point Transmission Service on the non-PTF using the curtailment priority pursuant to Schedule 21 of the Tariff. Such conditions must be identified in the Transmission Customer's Service Agreement.

System Impact Study is an assessment pursuant to Part II.B, II.C, II.G, Schedule 21, Schedule 22, Schedule 23, or Schedule 25 of the OATT of (i) the adequacy of the PTF or Non-PTF to accommodate a request for the interconnection of a new or materially changed generating unit or a new or materially changed interconnection to another Control Area or new Regional Network Service or new Local Service or an Elective Transmission Upgrade, and (ii) whether any additional costs may be required to be incurred in order to provide the interconnection or transmission service.

System Operator shall mean ISO New England Inc. or a successor organization.

System Operating Limit (SOL) has the meaning specified in the Glossary of Terms Used in NERC Reliability Standards.

System-Wide Capacity Demand Curve is the demand curve used in the Forward Capacity Market as specified in Section III.13.2.2.

TADO is the total amount due and owing (not including any amounts due under Section 14.1 of the RNA) at such time to the ISO, NEPOOL, the PTOs, the Market Participants and the Non-Market Participant Transmission Customers, by all PTOs, Market Participants and Non-Market Participant Transmission Customers.

Tangible Net Worth is the value, determined in accordance with international accounting standards or generally accepted accounting principles in the United States, of all of that entity's assets less the following: (i) assets the ISO reasonably believes to be restricted or potentially unavailable to settle a claim in the event of a default (e.g., regulatory assets, restricted assets, and Affiliate assets), net of any matching liabilities, to the extent that the result of that netting is a positive value; (ii) derivative assets, net of any matching liabilities, to the extent that the result of that netting is a positive value; (iii) the amount at which the liabilities of the entity would be shown on a balance sheet in accordance with international accounting standards or generally accepted accounting principles in the United States; (iv) preferred stock: (v) non-controlling interest; and (vi) all of that entity's intangible assets (e.g., patents, trademarks,

franchises, intellectual property, goodwill and any other assets not having a physical existence), in each case as shown on the most recent financial statements provided by such entity to the ISO.

Technical Committee is defined in Section 8.2 of the Participants Agreement.

Ten-Minute Non-Spinning Reserve (TMNSR) is a form of ten-minute reserve capability, determined pursuant to Section III.1.7.19.2.

Ten-Minute Non-Spinning Reserve Service is the form of Ancillary Service described in Schedule 6 of the OATT.

Ten-Minute Reserve Requirement is the combined amount of TMSR and TMNSR required system-wide as described in Section III.2.7A and ISO New England Operating Procedure No. 8.

Ten-Minute Spinning Reserve (TMSR) is a form of ten-minute reserve capability, determined pursuant to Section III.1.7.19.2.

Ten-Minute Spinning Reserve Requirement is the amount of TMSR required system-wide as described in Section III.2.7A and ISO New England Operating Procedure No. 8.

Ten-Minute Spinning Reserve Service is the form of Ancillary Service described in Schedule 5 of the OATT.

Third-Party Sale is any sale for resale in interstate commerce to a Power Purchaser that is not designated as part of Regional Network Load or Local Network Load under the Regional Network Service or Local Network Service, as applicable.

Thirty-Minute Operating Reserve (TMOR) is a form of thirty-minute reserve capability, determined pursuant to Section III.1.7.19.2.

Thirty-Minute Operating Reserve Service is the form of Ancillary Service described in Schedule 7 of the OATT.

Through or Out Rate (TOUT Rate) is the rate per hour for Through or Out Service, as defined in Section II.25.2 of the OATT.

Through or Out Service (TOUT Service) means Point-To-Point Service over the PTF provided by the ISO with respect to a transaction that goes through the New England Control Area, as, for example, a single transaction where energy or capacity is transmitted into the New England Control Area from New Brunswick and subsequently out of the New England Control Area to New York, or a single transaction where energy or capacity is transmitted into the New England Control Area from New York through one point on the PTF and subsequently flows over the PTF prior to passing out of the New England Control Area to New York, or with respect to a transaction which originates at a point on the PTF and flows over the PTF prior to passing out of the New England Control Area, as, for example, from Boston to New York.

Tie-Line Asset is a physical transmission tie-line, or an inter-state or intra-state border arrangement created according to the ISO New England Manuals and registered in accordance with the Asset Registration Process.

Total Available Amount is the sum of the available amount of the Shortfall Funding Arrangement and the balance in the Payment Default Shortfall Fund.

Total Blackstart Capital Payment is the annual compensation calculated under either Section 5.1 or Section 5.2 of Schedule 16 of the OATT, as applicable.

Total Blackstart Service Payments is monthly compensation to Blackstart Owners or Market Participants, as applicable, and as calculated pursuant to Section 5.6 of Schedule 16 to the OATT.

Total Reserve Requirement, which includes Replacement Reserve, is the combined amount of TMSR, TMNSR, and TMOR required system-wide as described in Section III.2.7A and ISO New England Operating Procedure No. 8.

Total System Capacity is the aggregate capacity supply curve for the New England Control Area as determined in accordance with Section III.13.2.3.3 of Market Rule 1.

Transaction Unit (TU) is a type of billing determinant under Schedule 2 of Section IV.A of the Tariff used to assess charges to Customers.

Transition Period: The six-year period commencing on March 1, 1997.

Transmission Charges, for the purposes of the ISO New England Financial Assurance Policy and the ISO New England Billing Policy, are all charges and payments under Schedules 1, 8 and 9 of the OATT.

Transmission Congestion Credit means the allocated share of total Transmission Congestion Revenue credited to each holder of Financial Transmission Rights, calculated and allocated as specified in Section III.5.2 of Market Rule 1.

Transmission Congestion Revenue is defined in Section III.5.2.5(a) of Market Rule 1.

Transmission Constraint Penalty Factors are described in Section III.1.7.5 of Market Rule 1.

Transmission Credit Limit is a credit limit, not to be used to meet FTR Requirements, established for each Market Participant in accordance with Section II.D and each Non-Market Participant Transmission Customer in accordance with Section V.B.2 of the ISO New England Financial Assurance Policy.

Transmission Credit Test Percentage is calculated in accordance with Section III.B.1(c) of the ISO New England Financial Assurance Policy.

Transmission Customer is any Eligible Customer that (i) executes, on its own behalf or through its Designated Agent, an MPSA or TSA, or (ii) requests in writing, on its own behalf or through its Designated Agent, that the ISO, the Transmission Owner, or the Schedule 20A Service Provider, as applicable, file with the Commission, a proposed unexecuted MPSA or TSA containing terms and conditions deemed appropriate by the ISO (in consultation with the applicable PTO, OTO or Schedule 20A Service Provider) in order that the Eligible Customer may receive transmission service under Section II of this Tariff. A Transmission Customer under Section II of this Tariff includes a Market Participant or a Non-Market Participant taking Regional Network Service, Through or Out Service, MTF Service, OTF Service, Ancillary Services, or Local Service.

Transmission Default Amount is all or any part of any amount of Transmission Charges due to be paid by any Covered Entity that the ISO, in its reasonable opinion, believes will not or has not been paid when due.

Transmission Default Period is defined in Section 3.4.f of the ISO New England Billing Policy.

Transmission Late Payment Account is defined in Section 4.2 of the ISO New England Billing Policy.

Transmission Late Payment Account Limit is defined in Section 4.2 of the ISO New England Billing Policy.

Transmission Late Payment Charge is defined in Section 4.1 of the ISO New England Billing Policy.

Transmission, Markets and Services Tariff (Tariff) is the ISO New England Inc. Transmission, Markets and Services Tariff, as amended from time to time.

Transmission Obligations are determined in accordance with Section III.A(vi) of the ISO New England Financial Assurance Policy.

Transmission Operating Agreement (TOA) is the Transmission Operating Agreement between and among the ISO and the PTOs, as amended and restated from time to time.

Transmission Owner means a PTO, MTO or OTO.

Transmission Provider is the ISO for Regional Network Service and Through or Out Service as provided under Section II.B and II.C of the OATT; Cross-Sound Cable, LLC for Merchant Transmission Service as provided under Schedule 18 of the OATT; the Schedule 20A Service Providers for Phase I/II HVDC-TF Service as provided under Schedule 20A of the OATT; and the Participating Transmission Owners for Local Service as provided under Schedule 21 of the OATT.

Transmission Requirements are determined in accordance with Section III.A(iii) of the ISO New England Financial Assurance Policy.

Transmission Security Analysis Requirement shall be determined pursuant to Section III.12.2.1.2.

Transmission Service Agreement (TSA) is the initial agreement and any amendments or supplements thereto: (A) in the form specified in either Attachment A or B to the OATT, entered into by the Transmission Customer and the ISO for Regional Network Service or Through or Out Service; (B) entered into by the Transmission Customer with the ISO and PTO in the form specified in Attachment A to Schedule 21 of the OATT; (C) entered into by the Transmission Customer with an OTO or Schedule 20A Service Provider in the appropriate form specified under Schedule 20 of the OATT; or (D) entered into by the Transmission Customer with a MTO in the appropriate form specified under Schedule 18 of the OATT. A Transmission Service Agreement shall be required for Local Service, MTF Service and OTF Service, and shall be required for Regional Network Service and Through or Out Service if the Transmission Customer has not executed a MPSA.

Transmission Upgrade(s) means an upgrade, modification or addition to the PTF that becomes subject to the terms and conditions of the OATT governing rates and service on the PTF on or after January 1, 2004. This categorization and cost allocation of Transmission Upgrades shall be as provided for in Schedule 12 of the OATT.

UDS is unit dispatch system software.

Unconstrained Export Transaction is defined in Section III.1.10.7(f)(iv) of Market Rule 1.

Uncovered Default Amount is defined in Section 3.3(i) of the ISO New England Billing Policy.

Uncovered Transmission Default Amounts are defined in Section 3.4.f of the ISO New England Billing Policy.

Unrated means a Market Participant that is not a Rated Market Participant.

Unsecured Covered Entity is, collectively, an Unsecured Municipal Market Participant and an Unsecured Non-Municipal Covered Entity.

Unsecured Municipal Default Amount is defined in Section 3.3(i) of the ISO New England Billing Policy.

Unsecured Municipal Market Participant is defined in Section 3.3(h) of the ISO New England Billing Policy.

Unsecured Municipal Transmission Default Amount is defined in Section 3.4.f of the ISO New England Billing Policy.

Unsecured Non-Municipal Covered Entity is a Covered Entity that is not a Municipal Market Participant or a Non-Market Participant Transmission Customer and has a Market Credit Limit or Transmission Credit Limit of greater than $0 under the ISO New England Financial Assurance Policy.

Unsecured Non-Municipal Default Amount is defined in Section 3.3(i) of the ISO New England Billing Policy.

Unsecured Non-Municipal Transmission Default Amount is defined in Section 3.3(i) of the ISO New England Billing Policy.

Unsecured Transmission Default Amounts are, collectively, the Unsecured Municipal Transmission Default Amount and the Unsecured Non-Municipal Transmission Default Amount.

Unsettled FTR Financial Assurance is an amount of financial assurance required from a Designated FTR Participant as calculated pursuant to Section VI.B of the ISO New England Financial Assurance Policy.

Updated Measurement and Verification Plan is an optional Measurement and Verification Plan that may be submitted as part of a subsequent qualification process for a Forward Capacity Auction prior to the beginning of the Capacity Commitment Period of the On-Peak Demand Resource or Seasonal Peak Demand Response project. The Updated Measurement and Verification Plan may include updated project specifications, measurement and verification protocols, and performance data as described in Section III.13.1.4.3.1.2 of Market Rule 1 and the ISO New England Manuals.

VAR CC Rate is the CC rate paid to Qualified Reactive Resources for VAR Service capability under Section IV.A of Schedule 2 of the OATT.

VAR Payment is the payment made to Qualified Reactive Resources for VAR Service capability under Section IV.A of Schedule 2 of the OATT.

VAR Service is the provision of reactive power voltage support to the New England Transmission System by a Qualified Reactive Resource or by other generators that are dispatched by the ISO to provide dynamic reactive power as described in Schedule 2 of the OATT.

Virtual Cap is $2,000/MWh.

Virtual Requirements are determined in accordance with Section III.A(iv) of the ISO New England Financial Assurance Policy.

Volt Ampere Reactive (VAR) is a measurement of reactive power.

Volumetric Measure (VM) is a type of billing determinant under Schedule 2 of Section IV.A of the Tariff used to assess charges to Customers under Section IV.A of the Tariff.

Winter ARA Qualified Capacity is described in Section III.13.4.2.1.2.1.1.2 of Market Rule 1.

Winter Capability Period means one of two time periods defined by the ISO for the purposes of rating and auditing resources pursuant to Section III.9. The time period associated with the Winter Capability Period is the period October 1 through May 31.

Winter Intermittent Reliability Hours are defined in Section III.13.1.2.2.2.2(c) of Market Rule 1.

Year means a period of 365 or 366 days, whichever is appropriate, commencing on, or on the anniversary of March 1, 1997. Year One is the Year commencing on March 1, 1997, and Years Two and higher follow it in sequence.

Zonal Price is calculated in accordance with Section III.2.7 of Market Rule 1.

Zonal Capacity Obligation is calculated in accordance with Section III.13.7.5.2 of Market Rule 1.

Zonal Reserve Requirement is the combined amount of TMSR, TMNSR, and TMOR required for a Reserve Zone as described in Section III.2.7A and ISO New England Operating Procedure No. 8.

STANDARD MARKET DESIGN

III.1 Market Operations

III.1.1 Introduction.

This Market Rule 1 sets forth the scheduling, other procedures, and certain general provisions applicable to the operation of the New England Markets within the New England Control Area. The ISO shall operate the New England Markets in compliance with NERC, NPCC and ISO reliability criteria. The ISO is the Counterparty for agreements and transactions with its Customers (including assignments involving Customers), including bilateral transactions described in Market Rule 1, and sales to the ISO and/or purchases from the ISO of energy, reserves, Ancillary Services, capacity, demand/load response, FTRs and other products, paying or charging (if and as applicable) its Customers the amounts produced by the pertinent market clearing process or through the other pricing mechanisms described in Market Rule 1. The bilateral transactions to which the ISO is the Counterparty (subject to compliance with the requirements of Section III.1.4) include, but are not limited to, Internal Bilaterals for Load, Internal Bilaterals for Market for Energy, Annual Reconfiguration Transactions, Capacity Supply Obligation Bilaterals, Capacity Load Obligation Bilaterals, Capacity Performance Bilaterals, and the transactions described in Sections III.9.4.1 (internal bilateral transactions that transfer Forward Reserve Obligations), and III.13.1.6 (Self-Supplied FCA Resources). Notwithstanding the foregoing, the ISO will not act as Counterparty for the import into the New England Control Area, for the use of Publicly Owned Entities, of: (1) energy, capacity, and ancillary products associated therewith, to which the Publicly Owned Entities are given preference under Articles 407 and 408 of the project license for the New York Power Authority's Niagara Project; and (2) energy, capacity, and ancillary products associated therewith, to which Publicly Owned Entities are entitled under Article 419 of the project license for the New York Power Authority's Franklin D. Roosevelt – St. Lawrence Project. This Market Rule 1 addresses each of the three time frames pertinent to the daily operation of the New England Markets: "Pre-scheduling" as specified in Section III.1.9, "Scheduling" as specified in III.1.10, and "Dispatch" as specified in III.1.11. This Market Rule 1 became effective on February 1, 2005.

III.1.2 [Reserved.]

III.1.3 Definitions.

Whenever used in Market Rule 1, in either the singular or plural number, capitalized terms shall have the meanings specified in Section I of the Tariff. Terms used in Market Rule 1 that are not defined in Section

I shall have the meanings customarily attributed to such terms by the electric utility industry in New England or as defined elsewhere in the ISO New England Filed Documents. Terms used in Market Rule 1 that are defined in Section I are subject to the 60% Participant Vote threshold specified in Section 11.1.2 of the Participants Agreement.

III.1.3.1 [Reserved.]

III.1.3.2 [Reserved.]

III.1.3.3 [Reserved.]

III.1.4 Requirements for Certain Transactions.

III.1.4.1 ISO Settlement of Certain Transactions.

The ISO will settle, and act as Counterparty to, the transactions described in Section III.1.4.2 if the transactions (and their related transactions) conform to, and the transacting Market Participants comply with, the requirements specified in Section III.1.4.3.

III.1.4.2 Transactions Subject to Requirements of Section III.1.4.

Transactions that must conform to the requirements of Section III.1.4 include: Internal Bilaterals for Load, Internal Bilaterals for Market for Energy, Annual Reconfiguration Transactions, Capacity Supply Obligation Bilaterals, Capacity Load Obligation Bilaterals, Capacity Performance Bilaterals, and the transactions described in Sections III.9.4.1 (internal bilateral transactions that transfer Forward Reserve Obligations), and III.13.1.6 (Self-Supplied FCA Resources). The foregoing are referred to collectively as "Section III.1.4 Transactions," and individually as a "Section III.1.4 Transaction." Transactions that conform to the standards are referred to collectively as "Section III.1.4 Conforming Transactions," and individually as a "Section III.1.4 Conforming Transaction."

III.1.4.3 Requirements for Section III.1.4 Conforming Transactions.

(a) To qualify as a Section III.1.4 Conforming Transaction, a Section III.1.4 Transaction must constitute an exchange for an off-market transaction (a "Related Transaction"), where the Related Transaction:

(i) is not cleared or settled by the ISO as Counterparty;

(ii) is a spot, forward or derivatives contract that contemplates the transfer of energy or a MW obligation to or from a Market Participant;

(iii) involves commercially appropriate obligations that impose a duty to transfer electricity or a MW obligation from the seller to the buyer, or from the buyer to the seller, with performance taking place within a reasonable time in accordance with prevailing cash market practices; and

(iv) is not contingent on either party to carry out the Section III.1.4 Transaction.

(b) In addition, to qualify as a Section III.1.4 Conforming Transaction:

(i) the Section III.1.4 Transaction must be executed between separate beneficial owners or separate parties trading for independently controlled accounts;

(ii) the Section III.1.4 Transaction and the Related Transaction must be separately identified in the records of the parties to the transactions; and

(iii) the Section III.1.4 Transaction must be separately identified in the records of the ISO.

(c) As further requirements:

(i) each party to the Section III.1.4 Transaction and Related Transaction must maintain, and produce upon request of the ISO, records demonstrating compliance with the requirements of Sections III.1.4.3(a) and (b) for the Section III.1.4 Transaction, the Related Transaction and any other transaction that is directly related to, or integrated in any way with, the Related Transaction, including the identity of the counterparties and the material economic terms of the transactions including their price, tenor, quantity and execution date; and

(ii) each party to the Section III.1.4 Transaction must be a Market Participant that meets all requirements of the ISO New England Financial Assurance Policy.

III.1.5 Resource Auditing.

III.1.5.1 Claimed Capability Audits.

III.1.5.1.1 General Audit Requirements.

(a) The following types of Claimed Capability Audits may be performed:

(i) An Establish Claimed Capability Audit establishes the Generator Asset's ability to respond to ISO Dispatch Instructions and to maintain performance at a specified output level for a specified duration.

(ii) A Seasonal Claimed Capability Audit determines a Generator Asset's capability to perform under specified summer and winter conditions for a specified duration.

(iii) A Seasonal DR Audit determines the ability of a Demand Response Resource to perform during specified months for a specified duration.

(iv) An ISO-Initiated Claimed Capability Audit is conducted by the ISO to verify the Generator Asset's Establish Claimed Capability Audit value or the Demand Response Resource's Seasonal DR Audit value.

(b) The Claimed Capability Audit value of a Generator Asset shall reflect any limitations based upon the interdependence of common elements between two or more Generator Assets such as: auxiliaries, limiting operating parameters, and the deployment of operating personnel.

(c) The Claimed Capability Audit value of gas turbine, combined cycle, and pseudo-combined cycle assets shall be normalized to standard 90° (summer) and 20° (winter) temperatures.

(d) The Claimed Capability Audit value for steam turbine assets with steam exports, combined cycle, or pseudo-combined cycle assets with steam exports where steam is exported for uses external to the electric power facility, shall be normalized to the facility's Seasonal Claimed Capability steam demand.

(e) A Claimed Capability Audit may be denied or rescheduled by the ISO if its performance will jeopardize the reliable operation of the electrical system.

III.1.5.1.2 Establish Claimed Capability Audit.

(a) An Establish Claimed Capability Audit may be performed only by a Generator Asset.

(b) The time and date of an Establish Claimed Capability Audit shall be unannounced.

(c) For a newly commercial Generator Asset:

(i) An Establish Claimed Capability Audit will be scheduled by the ISO within five Business Days of the commercial operation date for all Generator Assets except:

1. Non-intermittent daily cycle hydro;
2. Non-intermittent net-metered, or special qualifying facilities that do not elect to audit as described in Section III.1.5.1.3; and
3. Intermittent Generator Assets

(ii) The Establish Claimed Capability Audit values for both summer and winter shall equal the mean net real power output demonstrated over the duration of the audit, as reflected in hourly revenue metering data, normalized for temperature and steam exports.

(iii) The Establish Claimed Capability Audit values shall be effective as of the commercial operation date of the Generator Asset.

(d) For Generator Assets with an Establish Claimed Capability Audit value:

(i) An Establish Claimed Capability Audit may be performed at the request of a Market Participant in order to support a change in the summer and winter Establish Claimed Capability Audit values for a Generator Asset.

(ii) An Establish Claimed Capability Audit shall be performed within five Business Days of the date of the request.

(iii) The Establish Claimed Capability Audit values for both summer and winter shall equal the mean net real power output demonstrated over the duration of the audit, as reflected in hourly revenue metering data, normalized for temperature and steam exports.

(iv) The Establish Claimed Capability Audit values become effective one Business Day following notification of the audit results to the Market Participant by the ISO.

(v) A Market Participant may cancel an audit request prior to issuance of the audit Dispatch Instruction.

(e) An Establish Claimed Capability Audit value may not exceed the maximum interconnected flow specified in the Network Resource Capability for the resource associated with the Generator Asset.

(f) Establish Claimed Capability Audits shall be performed on non-NERC holiday weekdays between 0800 and 2200.

(g) To conduct an Establish Claimed Capability Audit, the ISO shall:

(i) Initiate an Establish Claimed Capability Audit by issuing a Dispatch Instruction ordering the Generator Asset's net output to increase from the current operating level to its Real-Time High Operating Limit.

(ii) Indicate when issuing the Dispatch Instruction that an audit will be conducted.

(iii) Begin the audit with the first full clock hour after sufficient time has been allowed for the asset to ramp, based on its offered ramp rate from its current operating point to reach its Real-Time High Operating Limit.

(h) An Establish Claimed Capability Audit shall be performed for the following contiguous duration:

Duration Required for an Establish Claimed Capability Audit	
Type	**Claimed Capability Audit Duration (Hrs)**
Steam Turbine (Includes Nuclear)	4
Combined Cycle	4
Integrated Coal Gasification Combustion Cycle	4
Pressurized Fluidized Bed Combustion	4

Combustion Gas Turbine	1
Internal Combustion Engine	1
Hydraulic Turbine – Reversible (Electric Storage) Hydraulic Turbine – Other	2
Hydro-Conventional Daily Pondage Hydro-Conventional Run of River Hydro-Conventional Weekly	2
Wind Photovoltaic Fuel Cell	2
Other Electric Storage (Excludes Hydraulic Turbine - Reversible)	2

(i) The ISO, in consultation with the Market Participant, will determine the contiguous audit duration for a Generator Asset of a type not listed in Section III.1.5.1.2(h).

III.1.5.1.3. Seasonal Claimed Capability Audits.

(a) A Seasonal Claimed Capability Audit may be performed only by a Generator Asset.

(b) A Seasonal Claimed Capability Audit must be conducted by all Generator Assets except:

(i) Non-intermittent daily hydro; and

(ii) Intermittent, net-metered, and special qualifying facilities. Non-intermittent net-metered and special qualifying facilities may elect to perform Seasonal Claimed Capability Audits pursuant to Section III.1.7.11(c)(iv).

(c) An Establish Claimed Capability Audit or ISO-Initiated Claimed Capability Audit that meets the requirements of a Seasonal Claimed Capability Audit in this Section III.1.5.1.3 may be used to fulfill a Generator Asset's Seasonal Claimed Capability Audit obligation.

(d) Except as provided in Section III.1.5.1.3(n) below, a summer Seasonal Claimed Capability Audit must be conducted:

(i) At least once every Capability Demonstration Year;

(ii) Either (1) at a mean ambient temperature during the audit that is greater than or equal to 80 degrees Fahrenheit at the location of the Generator Asset, or (2) during an ISO-announced summer Seasonal Claimed Capability Audit window.

(e) A winter Seasonal Claimed Capability Audit must be conducted:

(i) At least once in the previous three Capability Demonstration Years, except that a newly commercial Generator Asset which becomes commercial on or after:

(1) September 1 and prior to December 31 shall perform a winter Seasonal Claimed Capability Audit prior to the end of that Capability Demonstration Year.

(2) January 1 shall perform a winter Seasonal Claimed Capability Audit prior to the end of the next Capability Demonstration Year.

(ii) Either (1) at a mean ambient temperature during the audit that is less than or equal to 32 degrees Fahrenheit at the location of the Generator Asset, or (2) during an ISO-announced winter Seasonal Claimed Capability Audit window.

(f) A Seasonal Claimed Capability Audit shall be performed by operating the Generator Asset for the audit time period and submitting to the ISO operational data that meets the following requirements:

(i) The Market Participant must notify the ISO of its request to use the dispatch to satisfy the Seasonal Claimed Capability Audit requirement by 5:00 p.m. on the fifth Business Day following the day on which the audit concludes.

(ii) The notification must include the date and time period of the demonstration to be used for the Seasonal Claimed Capability Audit and other relevant operating data.

(g) The Seasonal Claimed Capability Audit value (summer or winter) will be the mean net real power output demonstrated over the duration of the audit, as reflected in hourly revenue metering data, normalized for temperature and steam exports.

(h) The Seasonal Claimed Capability Audit value (summer or winter) shall be the most recent audit data submitted to the ISO meeting the requirements of this Section III.1.5.1.3. In the event that a Market Participant fails to submit Seasonal Claimed Capability Audit data to meet the timing requirements in Section III.1.5.1.3(d) and (e), the Seasonal Claimed Capability Audit value for the season shall be set to zero.

(i) The Seasonal Claimed Capability Audit value shall become effective one Business Day following notification of the audit results to the Market Participant by the ISO.

(j) A Seasonal Claimed Capability Audit shall be performed for the following contiguous duration:

Duration Required for a Seasonal Claimed Capability Audit	
Type	**Claimed Capability Audit Duration (Hrs)**
Steam Turbine (Includes Nuclear)	2
Combined Cycle	2

Integrated Coal Gasification Combustion Cycle	2
Pressurized Fluidized Bed Combustion	2
Combustion Gas Turbine	1
Internal Combustion Engine	1
Hydraulic Turbine-Reversible (Electric Storage) Hydraulic Turbine-Other	2
Hydro-Conventional Weekly	2
Fuel Cell	1
Other Electric Storage (Excludes Hydraulic Turbine - Reversible)	2

(k) A Generator Asset that is on a planned outage that was approved in the ISO's annual maintenance scheduling process during all hours that meet the temperature requirements for a Seasonal Claimed Capability Audit that is to be performed by the asset during that Capability Demonstration Year shall:

(i) Submit to the ISO, prior to September 10, an explanation of the circumstances rendering it incapable of meeting these auditing requirements;

(ii) Have its Seasonal Claimed Capability Audit value for the season set to zero; and

(iii) Perform the required Seasonal Claimed Capability Audit on the next available day that meets the Seasonal Claimed Capability Audit temperature requirements.

(l) A Generator Asset that does not meet the auditing requirements of this Section III.1.5.1.3 because (1) every time the temperature requirements were met at the Generator Asset's location the ISO denied the request to operate to full capability, or (2) the temperature requirements were not met at the Generator Asset's location during the Capability Demonstration Year during which the asset was required to perform a Seasonal Claimed Capability Audit during the hours 0700 to 2300 for each weekday excluding those weekdays that are defined as NERC holidays, shall:

(i) Submit to the ISO, prior to September 10, an explanation of the circumstances rendering it incapable of meeting these temperature requirements, including verifiable temperature data;

(ii) Retain the current Seasonal Claimed Capability Audit value for the season; and

(iii) Perform the required Seasonal Claimed Capability Audit during the next Capability Demonstration Year.

(m) The ISO may issue notice of a summer or winter Seasonal Claimed Capability Audit window for some or all of the New England Control Area if the ISO determines that weather forecasts indicate that temperatures during the audit window will meet the summer or winter Seasonal

Claimed Capability Audit temperature requirements. A notice shall be issued at least 48 hours prior to the opening of the audit window. Any audit performed during the announced audit window shall be deemed to meet the temperature requirement for the summer or winter audit. In the event that five or more audit windows for the summer Seasonal Claimed Capability Audit temperature requirement, each of at least a four hour duration between 0700 and 2300 and occurring on a weekday excluding those weekdays that are defined as NERC holidays, are not opened for a Generator Asset prior to August 15 during a Capability Demonstration Year, a two-week audit window shall be opened for that Generator Asset to perform a summer Seasonal Claimed Capability Audit, and any audit performed by that Generator Asset during the open audit window shall be deemed to meet the temperature requirement for the summer Seasonal Claimed Capability Audit. The open audit window shall be between 0700 and 2300 each day during August 15 through August 31.

(n) A Market Participant that is required to perform testing on a Generator Asset that is in addition to a summer Seasonal Claimed Capability Audit may notify the ISO that the summer Seasonal Claimed Capability Audit was performed in conjunction with this additional testing, provided that:

(i) The notification shall be provided at the time the Seasonal Claimed Capability Audit data is submitted under Section III.1.5.1.3(f).

(ii) The notification explains the nature of the additional testing and that the summer Seasonal Claimed Capability Audit was performed while the Generator Asset was online to perform this additional testing.

(iii) The summer Seasonal Claimed Capability Audit and additional testing are performed during the months of June, July or August between the hours of 0700 and 2300.

(iv) In the event that the summer Seasonal Claimed Capability Audit does not meet the temperature requirements of Section III.1.5.1.3(d)(ii), the summer Seasonal Claimed Capability Audit value may not exceed the summer Seasonal Claimed Capability Audit value from the prior Capability Demonstration Year.

(v) This Section III.1.5.1.3(n) may be utilized no more frequently than once every three Capability Demonstration Years for a Generator Asset.

(o) The ISO, in consultation with the Market Participant, will determine the contiguous audit duration for a Generator Asset of a type not listed in Section III.1.5.1.3(j).

III.1.5.1.3.1 Seasonal DR Audits.

(a) A Seasonal DR Audit may be performed only by a Demand Response Resource.

(b) A Seasonal DR Audit shall be performed for 12 contiguous five-minute intervals.

(c) A summer Seasonal DR Audit must be conducted by all Demand Response Resources:

(i) At least once every Capability Demonstration Year;

(ii) During the months of April through November;

(d) A winter Seasonal DR Audit must be conducted by all Demand Response Resources:

(i) At least once every Capability Demonstration Year;

(ii) During the months of December through March.

(e) A Seasonal DR Audit may be performed either:

(i) At the request of a Market Participant as described in subsection (f) below; or

(ii) By the Market Participant designating a period of dispatch after the fact as described in subsection (g) below.

(f) If a Market Participant requests a Seasonal DR Audit:

(i) The ISO shall perform the Seasonal DR Audit at an unannounced time between 0800 and 2200 on non-NERC holiday weekdays within five Business Days of the date of the request.

(ii) The ISO shall initiate the Seasonal DR Audit by issuing a Dispatch Instruction ordering the Demand Response Resource to its Maximum Reduction.

(iii) The ISO shall indicate when issuing the Dispatch Instruction that an audit will be conducted.

(iv) The ISO shall begin the audit with the start of the first five-minute interval after sufficient time has been allowed for the resource to ramp, based on its Demand Reduction Offer parameters, to its Maximum Reduction.

(v) A Market Participant may cancel an audit request prior to issuance of the audit Dispatch Instruction.

(g) If the Seasonal DR Audit is performed by the designation of a period of dispatch after the fact, the designated period must meet all of the requirements in this Section III.1.5.1.3.1 and:

(i) The Market Participant must notify the ISO of its request to use the dispatch to satisfy the Seasonal DR Audit requirement by 5:00 p.m. on the fifth Business Day following the day on which the audit concludes.

(ii) The notification must include the date and time period of the demonstration to be used for the Seasonal DR Audit.

(iii) The demonstration period may begin with the start of any five-minute interval after the completion of the Demand Response Resource Notification Time.

(iv) A CLAIM10 audit or CLAIM30 audit that meets the requirements of a Seasonal DR Audit as provided in this Section III.1.5.1.3.1 may be used to fulfill the Seasonal DR Audit obligation of a Demand Response Resource.

(h) An ISO-Initiated Claimed Capability Audit fulfils the Seasonal DR Audit obligation of a Demand Response Resource.

(i) Each Demand Response Asset associated with a Demand Response Resource is evaluated during the Seasonal DR Audit of the Demand Response Resource.

(j) Any Demand Response Asset on a forced or scheduled curtailment as defined in Section III.8.3 is assessed a zero audit value.

(k) The Seasonal DR Audit value (summer or winter) of a Demand Response Resource resulting from the Seasonal DR Audit shall be the sum of the average demand reductions demonstrated during the audit by each of the Demand Response Resource's constituent Demand Response Assets.

(l) If a Demand Response Asset is added to or removed from a Demand Response Resource between audits, the Demand Response Resource's capability shall be updated to reflect the inclusion or exclusion of the audit value of the Demand Response Asset, such that at any point in time the summer or winter Seasonal DR Audit value of a Demand Response Resource shall equal the sum of the most recent valid like-season audit values of its constituent Demand Response Assets.

(m) The Seasonal DR Audit value shall become effective one calendar day following notification of the audit results to the Market Participant by the ISO.

(n) The summer or winter audit value of a Demand Response Asset shall be set to zero at the end of the Capability Demonstration Year if the Demand Response Asset did not perform a Seasonal DR Audit for that season as part of a Demand Response Resource during that Capability Demonstration Year.

(o) For a Demand Response Asset that was associated with a "Real-Time Demand Response Resource" or a "Real-Time Emergency Generation Resource," as those terms were defined prior to June 1, 2018, any valid result from an audit conducted prior to June 1, 2018 shall continue to be valid on June 1, 2018, and shall retain the same expiration date.

III.1.5.1.4. ISO-Initiated Claimed Capability Audits.

(a) An ISO-Initiated Claimed Capability Audit may be performed by the ISO at any time.

(b) An ISO-Initiated Claimed Capability Audit value shall replace either the summer or winter Seasonal DR Audit value for a Demand Response Resource and shall replace both the winter and summer Establish Claimed Capability Audit values for a Generator Asset, normalized for temperature and steam exports, except:

(i) The Establish Claimed Capability Audit values for a Generator Asset may not exceed the maximum interconnected flow specified in the Network Resource Capability for that resource.

(ii) An ISO-Initiated Claimed Capability Audit value for a Generator Asset shall not set the winter Establish Claimed Capability Audit value unless the ISO-Initiated Claimed Capability Audit was performed at a mean ambient temperature that is less than or equal to 32 degrees Fahrenheit at the Generator Asset location.

(c) If for a Generator Asset a Market Participant submits pressure and relative humidity data for the previous Establish Claimed Capability Audit and the current ISO-Initiated Claimed Capability Audit, the Establish Claimed Capability Audit values derived from the ISO-Initiated Claimed Capability Audit will be normalized to the pressure of the previous Establish Claimed Capability Audit and a relative humidity of 64%.

(d) The audit values derived from the ISO-Initiated Claimed Capability Audit shall become effective one Business Day following notification of the audit results to the Market Participant by the ISO.

(e) To conduct an ISO-Initiated Claimed Capability Audit, the ISO shall:

(i) Initiate an ISO-Initiated Claimed Capability Audit by issuing a Dispatch Instruction ordering the Generator Asset to its Real-Time High Operating Limit or the Demand Response Resource to its Maximum Reduction.

(ii) Indicate when issuing the Dispatch Instruction that an audit will be conducted.

(iii) For Generator Assets, begin the audit with the first full clock hour after sufficient time has been allowed for the Generator Asset to ramp, based on its offered ramp rate, from its current operating point to its Real-Time High Operating Limit.

(iv) For Demand Response Resources, begin the audit with the first five-minute interval after sufficient time has been allowed for the resource to ramp, based on its Demand Reduction Offer parameters, to its Maximum Reduction.

(f) An ISO-Initiated Claimed Capability Audit shall be performed for the following contiguous duration:

Duration Required for an ISO-Initiated Claimed Capability Audit	
Type	**Claimed Capability Audit Duration (Hrs)**
Steam Turbine (Includes Nuclear)	4
Combined Cycle	4

Integrated Coal Gasification Combustion Cycle	4
Pressurized Fluidized Bed Combustion	4
Combustion Gas Turbine	1
Internal Combustion Engine	1
Hydraulic Turbine – Reversible (Electric Storage) Hydraulic Turbine – Other	2
Hydro-Conventional Daily Pondage Hydro-Conventional Run of River Hydro-Conventional Weekly	2
Wind Photovoltaic Fuel Cell	2
Other Electric Storage (Excludes Hydraulic Turbine – Reversible)	2
Demand Response Resource	1

(g) The ISO, in consultation with the Market Participant, will determine the contiguous audit duration for an Asset or Resource type not listed in Section III.1.5.1.4(f).

III.1.5.2 ISO-Initiated Parameter Auditing.

(a) The ISO may perform an audit of any Supply Offer, Demand Reduction Offer or other operating parameter that impacts the ability of a Generator Asset or Demand Response Resource to provide real-time energy or reserves.

(b) Generator audits shall be performed using the following methods for the relevant parameter:

(i) **Economic Maximum Limit**. The Generator Asset shall be evaluated based upon its ability to achieve the current offered Economic Maximum Limit value, through a review of historical dispatch data or based on a response to a current ISO-issued Dispatch Instruction.

(ii) **Manual Response Rate**. The Generator Asset shall be evaluated based upon its ability to respond to Dispatch Instructions at its offered Manual Response Rate, including hold points and changes in Manual Response Rates.

(iii) **Start-Up Time**. The Generator Asset shall be evaluated based upon its ability to achieve the offered Start-Up Time.

(iv) **Notification Time**. The Generator Asset shall be evaluated based upon its ability to close its output breaker within its offered Notification Time.

(v) **CLAIM10**. The Generator Asset shall be evaluated based upon its ability to reach its CLAIM10 in accordance with Section III.9.5.

(vi) **CLAIM30**. The Generator Asset shall be evaluated based upon its ability to reach its CLAIM30 in accordance with Section III.9.5.

(vii) **Automatic Response Rate**. The Generator Asset shall be analyzed, based upon a review of historical performance data, for its ability to respond to four-second electronic Dispatch Instructions.

(viii) **Dual Fuel Capability**. A Generator Asset that is capable of operating on multiple fuels may be required to audit on a specific fuel, as set out in Section III.1.5.2(f).

(c) Demand Response Resource audits shall be performed using the following methods:

(i) **Maximum Reduction**. The Demand Response Resource shall be evaluated based upon its ability to achieve the current offered Maximum Reduction value, through a review of historical dispatch data or based on a response to a current Dispatch Instruction.

(ii) **Demand Response Resource Ramp Rate**. The Demand Response Resource shall be evaluated based upon its ability to respond to Dispatch Instructions at its offered Demand Response Resource Ramp Rate.

(iii) **Demand Response Resource Start-Up Time**. The Demand Response Resource shall be evaluated based upon its ability to achieve its Minimum Reduction within the offered Demand Response Resource Start-Up Time, in response to a Dispatch Instruction and after completing its Demand Response Resource Notification Time.

(iv) **Demand Response Resource Notification Time**. The Demand Response Resource shall be evaluated based upon its ability to start reducing demand within its offered Demand Response Resource Notification Time, from the receipt of a Dispatch Instruction when the Demand Response Resource was not previously reducing demand.

(v) **CLAIM10**. The Demand Response Resource shall be evaluated based upon its ability to reach its CLAIM10 in accordance with Section III.9.5.

(vi) **CLAIM30**. The Demand Response Resource shall be evaluated based upon its ability to reach its CLAIM30 in accordance with Section III.9.5.

(d) To conduct an audit based upon historical data, the ISO shall:

(i) Obtain data through random sampling of generator or Demand Response Resource performance in response to Dispatch Instructions; or

(ii) Obtain data through continual monitoring of generator or Demand Response Resource performance in response to Dispatch Instructions.

(e) To conduct an unannounced audit, the ISO shall initiate the audit by issuing a Dispatch Instruction ordering the Generator Asset or Demand Response Resource to change from the current operating level to a level that permits the ISO to evaluate the performance of the Generator Asset or Demand Response Resource for the parameters being audited.

(f) To conduct an audit of the capability of a Generator Asset described in Section III.1.5.2(b)(viii) to run on a specific fuel:

(i) The ISO shall notify the Lead Market Participant if a Generator Asset is required to undergo an audit on a specific fuel. The ISO, in consultation with the Lead Market Participant, shall develop a plan for the audit.

(ii) The Lead Market Participant will have the ability to propose the time and date of the audit within the ISO's prescribed time frame and must notify the ISO at least five Business Days in advance of the audit, unless otherwise agreed to by the ISO and the Lead Market Participant.

(g) To the extent that the audit results indicate a Market Participant is providing Supply Offer, Demand Reduction Offer or other operating parameter values that are not representative of the actual capability of the Generator Asset or Demand Response Resource, the values for the Generator Asset or Demand Response Resource shall be restricted to those values that are supported by the audit.

(h) In the event that a Generator Asset or Demand Response Resource has had a parameter value restricted:

(i) The Market Participant may submit a restoration plan to the ISO to restore that parameter. The restoration plan shall:

1. Provide an explanation of the discrepancy;
2. Indicate the steps that the Market Participant will take to re-establish the parameter's value;
3. Indicate the timeline for completing the restoration; and
4. Explain the testing that the Market Participant will undertake to verify restoration of the parameter value upon completion.

(ii) The ISO shall:

1. Accept the restoration plan if implementation of the plan, including the testing plan, is reasonably likely to support the proposed change in the parameter value restriction;
2. Coordinate with the Market Participant to perform required testing upon completion of the restoration; and
3. Modify the parameter value restriction following completion of the restoration plan, based upon tested values.

III.1.5.3 Reactive Capability Audits.

(a) Two types of Reactive Capability Audits may be performed:

(i) A lagging Reactive Capability Audit, which is an audit that measures a Reactive Resource's ability to provide reactive power to the transmission system at a specified real power output or consumption.

(ii) A leading Reactive Capability Audit, which is an audit that measures a Reactive Resource's ability to absorb reactive power from the transmission system at a specified real power output or consumption.

(b) The ISO shall develop a list of Reactive Resources that must conduct Reactive Capability Audits. The list shall include Reactive Resources that: (i) have a gross individual nameplate rating greater than 20 MVA; (ii) are directly connected, or are connected through equipment designed primarily for delivering real or reactive power to an interconnection point, to the transmission system at a voltage of 100 kV or above; and (iii) are not exempted from providing voltage control by the ISO. Additional criteria to be used in adding a Reactive Resource to the list includes, but is not limited to, the effect of the Reactive Resource on System Operating Limits, Interconnection Reliability Operating Limits, and local area voltage limits during the following operating states: normal, emergency, and system restoration.

(c) Unless otherwise directed by the ISO, Reactive Resources that are required to perform Reactive Capability Audits shall perform both a lagging Reactive Capability Audit and a leading Reactive Capability Audit.

(d) All Reactive Capability Audits shall meet the testing conditions specified in the ISO New England Operating Documents.

(e) The Reactive Capability Audit value of a Reactive Resource shall reflect any limitations based upon the interdependence of common elements between two or more Reactive Resources such as: auxiliaries, limiting operating parameters, and the deployment of operating personnel.

(f) A Reactive Capability Audit may be denied or rescheduled by the ISO if conducting the Reactive Capability Audit could jeopardize the reliable operation of the electrical system.

(g) Reactive Capability Audits shall be conducted at least every five years, unless otherwise required by the ISO. The ISO may require a Reactive Resource to conduct Reactive Capability Audits more often than every five years if:

(i) there is a change in the Reactive Resource that may affect the reactive power capability of the Reactive Resource;

(ii) there is a change in electrical system conditions that may affect the achievable reactive power output or absorption of the Reactive Resource; or

(iii) historical data shows that the amount of reactive power that the Reactive Resource can provide to or absorb from the transmission system is higher or lower than the latest audit data.

(h) A Lead Market Participant or Transmission Owner may request a waiver of the requirement to conduct a Reactive Capability Audit for its Reactive Resource. The ISO, at its sole discretion, shall determine whether and for how long a waiver may be granted.

III.1.6 [Reserved.]

III.1.6.1 [Reserved.]

III.1.6.2 [Reserved.]

III.1.6.3 [Reserved.]

III.1.6.4 ISO New England Manuals and ISO New England Administrative Procedures.

The ISO shall prepare, maintain and update the ISO New England Manuals and ISO New England Administrative Procedures consistent with the ISO New England Filed Documents. The ISO New England Manuals and ISO New England Administrative Procedures shall be available for inspection by the Market Participants, regulatory authorities with jurisdiction over the ISO or any Market Participant, and the public.

III.1.7 General.

III.1.7.1 Provision of Market Data to the Commission.

The ISO will electronically deliver to the Commission, on an ongoing basis and in a form and manner consistent with its collection of data and in a form and manner acceptable to the Commission, data related to the markets that it administers, in accordance with the Commission’s regulations.

III.1.7.2 [Reserved.]

III.1.7.3 Agents.

A Market Participant may participate in the New England Markets through an agent, provided that such Market Participant informs the ISO in advance in writing of the appointment of such agent. A Market Participant using an agent shall be bound by all of the acts or representations of such agent with respect to transactions in the New England Markets, and shall ensure that any such agent complies with the

requirements of the ISO New England Manuals and ISO New England Administrative Procedures and the ISO New England Filed Documents.

III.1.7.4 [Reserved.]

III.1.7.5 Transmission Constraint Penalty Factors.

In the Day-Ahead Energy Market, the Transmission Constraint Penalty Factor for an interface constraint is $10,000/MWh and the Transmission Constraint Penalty Factor for all other transmission constraints is $30,000/MWh. In the Real-Time Energy Market, the Transmission Constraint Penalty Factor for any transmission constraint is $30,000/MWh. Transmission Constraint Penalty Factors are not used in calculating Locational Marginal Prices.

III.1.7.6 Scheduling and Dispatching.

(a) The ISO shall schedule Day-Ahead and schedule and dispatch in Real-Time Resources economically on the basis of least-cost, security-constrained dispatch and the prices and operating characteristics offered by Market Participants. The ISO shall schedule and dispatch sufficient Resources of the Market Participants to serve the New England Markets energy purchase requirements under normal system conditions of the Market Participants and meet the requirements of the New England Control Area for ancillary services provided by such Resources. The ISO shall use a joint optimization process to serve Real-Time Energy Market energy requirements and meet Real-Time Operating Reserve requirements based on a least-cost, security-constrained economic dispatch. Commencing on June 1, 2024, the ISO shall use a joint optimization process to serve Day-Ahead Energy Market energy requirements and Day-Ahead Ancillary Services requirements based on a security-constrained economic commitment and dispatch.

(b) In the event that one or more Resources cannot be scheduled in the Day-Ahead Energy Market on the basis of a least-cost, security-constrained economic commitment and dispatch as a result of one or more Self-Schedule offers contributing to a transmission limit violation, the following scheduling protocols will apply:

(i) When a single Self-Schedule offer contributes to a transmission limit violation, the Self-Schedule offer will not be scheduled for the entire Self-Schedule period in development of Day-Ahead schedules.

(ii) When two Self-Schedule offers contribute to a transmission limit violation, parallel clearing solutions will be executed such that, for each solution, one of the Self-Schedule offers will be omitted for its entire Self-Schedule period. The least cost solution will be used for purposes of determining which Resources are scheduled in the Day-Ahead Energy Market.

(iii) When three or more Self-Schedule offers contribute to a transmission limit violation, the ISO will determine the total daily MWh for each Self-Schedule offer and will omit Self-Schedule offers in their entirety, in sequence from the offer with the least total daily MWh to the offer with the greatest total MWh, stopping when the transmission limit violation is resolved.

(c) Scheduling and dispatch shall be conducted in accordance with the ISO New England Filed Documents.

(d) The ISO shall undertake, together with Market Participants, to identify any conflict or incompatibility between the scheduling or other deadlines or specifications applicable to the New England Markets, and any relevant procedures of another Control Area, or any tariff (including the Transmission, Markets and Services Tariff). Upon determining that any such conflict or incompatibility exists, the ISO shall propose tariff or procedural changes, or undertake such other efforts as may be appropriate, to resolve any such conflict or incompatibility.

III.1.7.7 Energy Pricing.

The price paid for energy, including demand reductions, bought and sold by the ISO in the New England Markets will reflect the Locational Marginal Price at each Location, determined by the ISO in accordance with the ISO New England Filed Documents. Congestion Costs, which shall be determined by differences in the Congestion Component of Locational Marginal Prices caused by constraints, shall be calculated and collected, and the resulting revenues disbursed, by the ISO in accordance with this Market Rule 1. Loss costs associated with Pool Transmission Facilities, which shall be determined by the differences in Loss Components of the Locational Marginal Prices shall be calculated and collected, and the resulting revenues disbursed, by the ISO in accordance with this Market Rule 1.

III.1.7.8 Market Participant Resources.

A Market Participant may elect to Self-Schedule its Resources in accordance with and subject to the limitations and procedures specified in this Market Rule 1 and the ISO New England Manuals.

III.1.7.8A Day-Ahead Ancillary Services Prices.

The prices paid by the ISO for the provision of Day-Ahead Ancillary Services in the New England Markets will reflect Day-Ahead Ancillary Services clearing prices determined by the ISO in accordance with the ISO New England Filed Documents.

III.1.7.9 Real-Time Reserve Prices.

The price paid by the ISO for the provision of Real-Time Operating Reserve in the New England Markets will reflect Real-Time Reserve Clearing Prices determined by the ISO in accordance with the ISO New England Filed Documents for the system and each Reserve Zone.

III.1.7.10 Other Transactions.

Market Participants may enter into internal bilateral transactions and External Transactions for the purchase or sale of energy or other products to or from each other or any other entity, subject to the obligations of Market Participants to make resources with a Capacity Supply Obligation available for dispatch by the ISO. External Transactions that contemplate the physical transfer of energy or obligations to or from a Market Participant shall be reported to and coordinated with the ISO in accordance with this Market Rule 1 and the ISO New England Manuals.

III.1.7.11 Seasonal Claimed Capability of a Generating Capacity Resource.

(a) A Seasonal Claimed Capability value must be established and maintained for all Generating Capacity Resources. A summer Seasonal Claimed Capability is established for use from June 1 through September 30 and a winter Seasonal Claimed Capability is established for use from October 1 through May 31.

(b) The Seasonal Claimed Capability of a Generating Capacity Resource is the sum of the Seasonal Claimed Capabilities of the Generator Assets that are associated with the Generating Capacity Resource.

(c) The Seasonal Claimed Capability of a Generator Asset is:

(i) Based upon review of historical data for non-intermittent daily cycle hydro.

(ii) The median net real power output during reliability hours, as described in Section III.13.1.2.2.2, for (1) intermittent facilities, and (2) net-metered and special qualifying facilities that do not elect to audit, as reflected in hourly revenue metering data.

(iii) For non-intermittent net-metered and special qualifying facilities that elect to audit, the minimum of (1) the Generator Asset's current Seasonal Claimed Capability Audit value, as performed

pursuant to Section III.1.5.1.3; (2) the Generator Asset's current Establish Claimed Capability Audit value; and (3) the median hourly availability during hours ending 2:00 p.m. through 6:00 p.m. each day of the preceding June through September for Summer and hours ending 6:00 p.m. and 7:00 p.m. each day of the preceding October through May for Winter. The hourly availability:

a. For a Generator Asset that is available for commitment and following Dispatch Instructions, shall be the asset's Economic Maximum Limit, as submitted or redeclared.
b. For a Generator Asset that is off-line and not available for commitment shall be zero.
c. For a Generator Asset that is on-line but not able to follow Dispatch Instructions, shall be the asset's metered output.

(iv) For all other Generator Assets, the minimum of: (1) the Generator Asset's current Establish Claimed Capability Audit value and (2) the Generator Asset's current Seasonal Claimed Capability Audit value, as performed pursuant to Section III.1.5.1.3.

III.1.7.12 Seasonal DR Audit Value of an Active Demand Capacity Resource.

(a) A Seasonal DR Audit value must be established and maintained for all Active Demand Capacity Resources. A summer Seasonal DR Audit value is established for use from April 1 through November 30 and a winter Seasonal DR Audit value is established for use from December 1 through March 31.

(b) The Seasonal DR Audit value of an Active Demand Capacity Resource is the sum of the Seasonal DR Audit values of the Demand Response Resources that are associated with the Active Demand Capacity Resource.

III.1.7.13 [Reserved.]

III.1.7.14 [Reserved.]

III.1.7.15 [Reserved.]

III.1.7.16 [Reserved.]

III.1.7.17 Operating Reserve.

The ISO shall endeavor to procure and maintain an amount of Operating Reserve in Real-Time equal to the system and zonal Operating Reserve requirements as specified in the ISO New England Manuals and ISO New England Administrative Procedures. Reserve requirements for the Forward Reserve Market are determined in accordance with the methodology specified in Section III.9.2 of Market Rule 1. Operating

Reserve requirements for Real-Time dispatch within an Operating Day are determined in accordance with Market Rule 1 and ISO New England Operating Procedure No. 8, Operating Reserve and Regulation.

III.1.7.18 Ramping.

A Generator Asset, Dispatchable Asset Related Demand, or Demand Response Resource dispatched by the ISO pursuant to a control signal appropriate to increase or decrease the Resource's megawatt output, consumption, or demand reduction level shall be able to change output, consumption, or demand reduction at the ramping rate specified in the Offer Data submitted to the ISO for that Resource and shall be subject to sanctions for failure to comply as described in **Appendix B**.

III.1.7.19 Real-Time Reserve Designation.

The ISO shall determine the Real-Time Reserve Designation for each eligible Resource in accordance with this Section III.1.7.19. The Real-Time Reserve Designation shall consist of a MW value, in no case less than zero, for each Operating Reserve product: Ten-Minute Spinning Reserve, Ten-Minute Non-Spinning Reserve, and Thirty-Minute Operating Reserve.

III.1.7.19.1 Eligibility.

To be eligible to receive a Real-Time Reserve Designation, a Resource must meet all of the criteria enumerated in this Section III.1.7.19.1. A Resource that does not meet all of these criteria is not eligible to provide Operating Reserve and will not receive a Real-Time Reserve Designation.

(1) The Resource must be a Dispatchable Resource located within the metered boundaries of the New England Control Area and capable of receiving and responding to electronic Dispatch Instructions.

(2) The Resource must not be part of the first contingency supply loss.

(3) The Resource must not be designated as constrained by transmission limitations.

(4) The Resource's Operating Reserve, if activated, must be sustainable for at least one hour from the time of activation. (This eligibility requirement does not affect a Resource's obligation to follow Dispatch Instructions, even after one hour from the time of activation.)

(5) The Resource must comply with the applicable standards and requirements for provision and dispatch of Operating Reserve as specified in the ISO New England Manuals and ISO New England Administrative Procedures.

III.1.7.19.2 Calculation of Real-Time Reserve Designation.

III.1.7.19.2.1 Generator Assets.

III.1.7.19.2.1.1 On-line Generator Assets.

The Manual Response Rate used in calculations in this section shall be the lesser of the Generator Asset's offered Manual Response Rate and its audited Manual Response Rate as described in Section III.1.5.2.

(a) **Ten-Minute Spinning Reserve.** For an on-line Generator Asset (other than one registered as being composed of multiple generating units whose synchronized capability cannot be determined by the ISO), Ten-Minute Spinning Reserve shall be calculated as the increase in output the Generator Asset could achieve, relative to its current telemetered output, within ten minutes given its Manual Response Rate (and in no case to a level greater than its Economic Maximum Limit). For an on-line Generator Asset registered as being composed of multiple generating units whose synchronized capability cannot be determined by the ISO, Ten-Minute Spinning Reserve shall be zero.

(b) **Ten-Minute Non-Spinning Reserve.** For an on-line Generator Asset (other than one registered as being composed of multiple generating units whose synchronized capability cannot be determined by the ISO), Ten-Minute Non-Spinning Reserve shall be zero. For an on-line Generator Asset registered as being composed of multiple generating units whose synchronized capability cannot be determined by the ISO, Ten-Minute Non-Spinning Reserve shall be calculated as the increase in output the Generator Asset could achieve, relative to its current telemetered output, within ten minutes given its Manual Response Rate (and in no case to a level greater than its Economic Maximum Limit).

(c) **Thirty-Minute Operating Reserve.** For an on-line Generator Asset, Thirty-Minute Operating Reserve shall be calculated as the increase in output the Generator Asset could achieve, relative to its current telemetered output, within thirty minutes given its Manual Response Rate (and in no case greater than its Economic Maximum Limit) minus the Ten-Minute Spinning Reserve quantity calculated for the Generator Asset pursuant to subsection (a) above and the Ten-Minute Non-Spinning Reserve quantity calculated for the Generator Asset pursuant to subsection (b) above.

III.1.7.19.2.1.2 Off-line Generator Assets.

For an off-line Generator Asset that is not a Fast Start Generator, all components of the Real-Time Reserve Designation shall be zero.

(a) **Ten-Minute Spinning Reserve.** For an off-line Fast Start Generator, Ten-Minute Spinning Reserve shall be zero.

(b) **Ten-Minute Non-Spinning Reserve.** For an off-line Fast Start Generator, Ten-Minute Non-Spinning Reserve shall be calculated as the minimum of the Fast Start Generator's Offered CLAIM10, its CLAIM10, and its Economic Maximum Limit (provided, however, that during the Fast Start Generator's Minimum Down Time, the Fast Start Generator's Ten-Minute Non-Spinning Reserve shall be zero, except during the last ten minutes of its Minimum Down Time, at which time the ISO will prorate the Fast Start Generator's Ten-Minute Non-Spinning Reserve to account for the remaining amount of time until the Fast Start Generator's Minimum Down Time expires).

(c) **Thirty-Minute Operating Reserve.** For an off-line Fast Start Generator, Thirty-Minute Operating Reserve shall be calculated as: (i) the minimum of the Fast Start Generator's Offered CLAIM30, its CLAIM30, and its Economic Maximum Limit (provided, however, that during the Fast Start Generator's Minimum Down Time, the Fast Start Generator's Thirty-Minute Operating Reserve shall be zero, except during the last thirty minutes of its Minimum Down Time, at which time the ISO will prorate the Fast Start Generator's Thirty-Minute Operating Reserve to account for the remaining amount of time until the Fast Start Generator's Minimum Down Time expires), minus (ii) the Ten-Minute Non-Spinning Reserve quantity calculated for the Fast Start Generator pursuant to subsection (b) above.

III.1.7.19.2.2 Dispatchable Asset Related Demand.

III.1.7.19.2.2.1 Storage DARDs.

(a) **Ten-Minute Spinning Reserve.** For a Storage DARD, Ten-Minute Spinning Reserve shall be calculated as the absolute value of the amount of current telemetered consumption.

(b) **Ten-Minute Non-Spinning Reserve.** For a Storage DARD, Ten-Minute Non-Spinning Reserve shall be zero.

(c) **Thirty-Minute Operating Reserve.** For a Storage DARD, Thirty-Minute Operating Reserve shall be zero.

III.1.7.19.2.2.2 Dispatchable Asset Related Demand Other Than Storage DARDs.

(a) **Ten-Minute Spinning Reserve.** For a Dispatchable Asset Related Demand (other than a Storage DARD) that has no Controllable Behind-the-Meter Generation, Ten-Minute Spinning Reserve shall be calculated as the decrease in consumption that the Dispatchable Asset Related Demand could achieve, relative to its current telemetered consumption, within ten minutes given its ramp rate (and in no case to an amount less than its Minimum Consumption Limit). For a Dispatchable Asset Related Demand (other than a Storage DARD) having Controllable Behind-the-Meter Generation, Ten-Minute Spinning Reserve shall be zero.

(b) **Ten-Minute Non-Spinning Reserve.** For a Dispatchable Asset Related Demand (other than a Storage DARD) that has no Controllable Behind-the-Meter Generation, Ten-Minute Non-Spinning Reserve shall be zero. For a Dispatchable Asset Related Demand (other than a Storage DARD) having Controllable Behind-the-Meter Generation, Ten-Minute Non-Spinning Reserve shall be calculated as the decrease in consumption that the Dispatchable Asset Related Demand could achieve, relative to its current telemetered consumption, within ten minutes given its ramp rate (and in no case to an amount less than its Minimum Consumption Limit).

(c) **Thirty-Minute Operating Reserve.** For a Dispatchable Asset Related Demand (other than a Storage DARD) that has no Controllable Behind-the-Meter Generation, Thirty-Minute Operating Reserve shall be calculated as the decrease in consumption that the Dispatchable Asset Related Demand could achieve, relative to its current telemetered consumption, within thirty minutes given its ramp rate (and in no case to an amount less than its Minimum Consumption Limit) minus the Ten-Minute Spinning Reserve quantity calculated for the Dispatchable Asset Related Demand pursuant to subsection (a) above. For a Dispatchable Asset Related Demand (other than a Storage DARD) having Controllable Behind-the-Meter Generation, Thirty-Minute Operating Reserve shall be calculated as the decrease in consumption that the Dispatchable Asset Related Demand could achieve, relative to its current telemetered consumption, within thirty minutes given its ramp rate (and in no case to an amount less than its Minimum Consumption Limit)

minus the Ten-Minute Non-Spinning Reserve quantity calculated for the Dispatchable Asset Related Demand pursuant to subsection (b) above.

III.1.7.19.2.3 Demand Response Resources.

For a Demand Response Resource that does not provide one-minute telemetry to the ISO, notwithstanding any provision in this Section III.1.7.19.2.3 to the contrary, the Ten-Minute Spinning Reserve and Ten-Minute Non-Spinning Reserve components of the Real-Time Reserve Designation shall be zero. The Demand Response Resource Ramp Rate used in calculations in this section shall be the lesser of the Resource's offered Demand Response Resource Ramp Rate and its audited Demand Response Resource Ramp Rate as described in Section III.1.5.2.

III.1.7.19.2.3.1 Dispatched.

(a) **Ten-Minute Spinning Reserve.** For a Demand Response Resource that is being dispatched and that has no Controllable Behind-the-Meter Generation, Ten-Minute Spinning Reserve shall be calculated as the increase in demand reduction that the Demand Response Resource could achieve, relative to the estimated current demand reduction level, within ten minutes given its Demand Response Resource Ramp Rate (and in no case greater than its Maximum Reduction). For a Demand Response Resource that is being dispatched and that has Controllable Behind-the-Meter Generation, Ten-Minute Spinning Reserve shall be zero.

(b) **Ten-Minute Non-Spinning Reserve.** For a Demand Response Resource that is being dispatched and that has no Controllable Behind-the-Meter Generation, Ten-Minute Non-Spinning Reserve shall be zero. For a Demand Response Resource that is being dispatched and that has Controllable Behind-the-Meter Generation, Ten-Minute Non-Spinning Reserve shall be calculated as the increase in demand reduction that the Demand Response Resource could achieve, relative to the estimated current demand reduction level, within ten minutes given its Demand Response Resource Ramp Rate (and in no case greater than its Maximum Reduction).

(c) **Thirty-Minute Operating Reserve.** For a Demand Response Resource that is being dispatched, Thirty-Minute Operating Reserve shall be calculated as the increase in demand reduction that the Demand Response Resource could achieve, relative to the estimated current demand reduction level, within thirty minutes given its Demand Response Resource Ramp Rate (and in no case greater than its Maximum Reduction) minus the Ten-Minute Spinning Reserve quantity

calculated for the Resource pursuant to subsection (a) above and the Ten-Minute Non-Spinning Reserve quantity calculated for the Resource pursuant to subsection (b) above.

III.1.7.19.2.3.2 Non-Dispatched.

For a Demand Response Resource that is not being dispatched that is not a Fast Start Demand Response Resource, all components of the Real-Time Reserve Designation shall be zero.

(a) **Ten-Minute Spinning Reserve.** For a Fast Start Demand Response Resource that is not being dispatched, Ten-Minute Spinning Reserve shall be zero.

(b) **Ten-Minute Non-Spinning Reserve.** For a Fast Start Demand Response Resource that is not being dispatched, Ten-Minute Non-Spinning Reserve shall be calculated as the minimum of the Demand Response Resource's Offered CLAIM10, its CLAIM10, and its Maximum Reduction.

(c) **Thirty-Minute Operating Reserve.** For a Fast Start Demand Response Resource that is not being dispatched, Thirty-Minute Operating Reserve shall be calculated as: (i) the minimum of the Demand Response Resource's Offered CLAIM30, its CLAIM30, and its Maximum Reduction, minus (ii) the Ten-Minute Non-Spinning Reserve quantity calculated for the Demand Response Resource pursuant to subsection (b) above.

III.1.7.20 Information and Operating Requirements.

(a) [Reserved.]

(b) Market Participants selling from Resources within the New England Control Area shall: supply to the ISO all applicable Offer Data; report to the ISO Resources that are Self-Scheduled; report to the ISO External Transaction sales; confirm to the ISO bilateral sales to Market Participants within the New England Control Area; respond to the ISO's directives to start, shutdown or change output, consumption, or demand reduction levels of Generator Assets, DARDs, or Demand Response Resources, change scheduled voltages or reactive output levels; continuously maintain all Offer Data concurrent with on-line operating information; and ensure that, where so equipped, equipment is operated with control equipment functioning as specified in the ISO New England Manuals and ISO New England Administrative Procedures.

(c) Market Participants selling from Resources outside the New England Control Area shall: provide to the ISO all applicable Offer Data, including offers specifying amounts of energy available, hours of availability and prices of energy and other services; respond to ISO directives to schedule delivery or change delivery schedules; and communicate delivery schedules to the source Control Area and any intermediary Control Areas.

(d) Market Participants, as applicable, shall: respond or ensure a response to ISO directives for load management steps; report to the ISO all bilateral purchase transactions including External Transaction purchases; and respond or ensure a response to other ISO directives such as those required during Emergency operation.

(e) Market Participant, as applicable, shall provide to the ISO requests to purchase specified amounts of energy for each hour of the Operating Day during which it intends to purchase from the Day-Ahead Energy Market.

(f) Market Participants are responsible for reporting to the ISO anticipated availability and other information concerning Generator Assets, Demand Response Resources and Dispatchable Asset Related Demands required by the ISO New England Operating Documents, including but not limited to the Market Participant's ability to procure fuel and physical limitations that could reduce Resource output or demand reduction capability for the pertinent Operating Day.

III.1.8 Energy Call Option Offers and Day-Ahead Ancillary Services Demand Quantities.

III.1.8.1 Applicability.

The provisions of this Section III.1.8 apply commencing on June 1, 2024.

III.1.8.2 Energy Call Option Offers.

Market Participants may submit Energy Call Option Offers for the Operating Day as specified in this Section III.1.8.2.

(a) Each Energy Call Option Offer shall be associated with a specific Generator Asset or Demand Response Resource for which the Market Participant has submitted a corresponding Supply Offer or Demand Reduction Offer in the Day-Ahead Energy Market for the same hour of the Operating Day.

(b) Each Energy Call Option Offer shall specify: (i) the hour of the Operating Day for which the Energy Call Option Offer applies; (ii) an offer price, in $/MWh, that is greater than or equal to zero; and (iii) an offer quantity, in MWh, that is greater than or equal to zero. The offer price shall not exceed the Reserve Constraint Penalty Factor value specified in Section III.2.6.2(b)(vi) of this Market Rule 1. The offer quantity shall not exceed the Economic Maximum Limit specified in the associated Supply Offer or the Maximum Reduction specified in the associated Demand Reduction Offer.

(c) For each hour of the Operating Day, a Market Participant may submit only one Energy Call Option Offer associated with a specific Generator Asset or Demand Response Resource.

(d) Energy Call Option Offers shall be submitted by the offer submission deadline for the Day-Ahead Energy Market specified in Section III.1.10.1A of this Market Rule 1. An Energy Call Option Offer shall not remain in effect for subsequent Operating Days.

III.1.8.3 Energy Call Option Strike Price.

For each hour of the Operating Day, the ISO shall specify the Energy Call Option Strike Price in $/MWh. The value of the Energy Call Option Strike Price shall represent a forecast of the expected hourly Real-Time Hub Price for each hour of the Operating Day plus $10/MWh.

The forecast used to determine the Energy Call Option Strike Price shall be based on a publicly-available forecasting algorithm. The ISO shall identify the publicly-available forecasting algorithm and shall review any potential revisions to the forecasting process, prospectively, through the stakeholder process.

The ISO shall post, publicly, the value of the Energy Call Option Strike Price for each hour of the Operating Day no later than two hours before the offer submission deadline for the Day-Ahead Energy Market specified in Section III.1.10.1A of this Market Rule 1, or such other time as necessary to account for software failures or other events.

III.1.8.4 [Reserved.]

III.1.8.5 Day-Ahead Ancillary Services Demand Quantities.

The Day-Ahead Energy Market shall endeavor to procure the demand quantities for the Day-Ahead Ancillary Services specified in this Section III.1.8.5.

(a) For each hour of the Operating Day, the Day-Ahead Ten-Minute Spinning Reserve Demand Quantity shall be equal to the projected Ten-Minute Spinning Reserve Requirement as described in Section III.2.7A of this Market Rule 1 and ISO New England Operating Procedure No. 8.

(b) For each hour of the Operating Day, the Day-Ahead Total Ten-Minute Reserve Demand Quantity shall be equal to the projected Ten-Minute Reserve Requirement as described in Section III.2.7A of this Market Rule 1 and ISO New England Operating Procedure No. 8.

(c) For each hour of the Operating Day, the Day-Ahead Total Thirty-Minute Operating Reserve Demand Quantity shall be equal to the projected Minimum Total Reserve Requirement as described in Section III.2.7A of this Market Rule 1 and ISO New England Operating Procedure No. 8.

(d) For each hour of the Operating Day from December 1 through February 28/29, the Day-Ahead Total Ninety-Minute Reserve Demand Quantity shall be the reserve capability sufficient to satisfy the requirements in NERC Reliability Standard BAL-002-3 – Disturbance Control Standard – Contingency Reserve for Recovery from a Balancing Contingency Event, including the restoration of Contingency Reserve within the Contingency Reserve Restoration Period. For each hour of the Operating Day from March 1 through November 30, the Day-Ahead Total Ninety-Minute Reserve Demand Quantity shall be zero.

(e) For each hour of the Operating Day from December 1 through February 28/29, the Day-Ahead Total Four-Hour Reserve Demand Quantity shall be the reserve capability sufficient to satisfy the requirements of NPCC Regional Reliability Reference Directory No. 5 Reserve, including the restoration of Thirty-Minute Operating Reserve within four hours of a deficiency. For each hour of the Operating Day from March 1 through November 30, the Day-Ahead Total Four-Hour Reserve Demand Quantity shall be zero.

(f) For each hour of the Operating Day, the Day-Ahead Energy Imbalance Reserve Demand Quantity shall be determined during the scheduling of the Day-Ahead Energy Market. The Day-Ahead Energy Imbalance Reserve Demand Quantity shall be equal to the greater of (a) zero or (b) the value of:
(i) the Forecast Energy Requirement Demand Quantity; less (ii) the sum of the total MWh of all Supply Offers and the total MWh of all Demand Reduction Offers that receive the forecast energy requirement

credit, as specified in Section III.3.2.1(q)(5); less (iii) the net total External Transactions (imports minus exports, in MWh) scheduled in the Day-Ahead Energy Market.

III.1.8.6 Forecast Energy Requirement Demand Quantity.

For each hour of the Operating Day, the Forecast Energy Requirement Demand Quantity shall be equal to the ISO forecast for the total loads in the New England Control Area produced pursuant to Section III.1.10.1.A(h) of this Market Rule 1.

III.1.9 Pre-scheduling.

III.1.9.1 Offer and Bid Caps and Cost Verification for Offers and Bids.

III.1.9.1.1 Cost Verification of Resource Offers.

The incremental energy values of Supply Offers and Demand Response Resources above $1,000/MWh for any Resource other than an External Resource are subject to the following cost verification requirements. Unless expressly stated otherwise, cost verification is utilized in all pricing, commitment, dispatch and settlement determinations. For purposes of the following requirements, Reference Levels are calculated using the procedures in Section III.A.7.5 for calculating cost-based Reference Levels.

(a) If the incremental energy value of a Resource's offer is greater than the incremental energy Reference Level value of the Resource, then the incremental energy value in the offer is replaced with the greater of the Reference Level for incremental energy or $1,000/MWh.

(b) For purposes of the price calculations in Sections III.2.5 and III.2.7A, if the adjusted offer calculated under Section III.2.4 for a Rapid Response Pricing Asset is greater than $1,000/MWh (after the incremental energy value is evaluated under Section III.1.9.1.1(a) above), then verification will be performed as follows using a Reference Level value calculated with the adjusted offer formulas specified in Section III.2.4.

(i) If the Reference Level value is less than or equal to $1,000/MWh, then the adjusted offer for the Resource is set at $1,000/MWh;

(ii) If the Reference Level value is greater than $1,000/MWh, then the adjusted offer for the Resource is set at the lower of the Reference Level value and the adjusted offer.

III.1.9.1.2 Offer and Bid Caps.

(a) For purposes of the price calculations described in Section III.2 and for purposes of scheduling a Resource in the Day-Ahead Energy Market in accordance with Section III.1.7.6 following the commitment of the Resource, the incremental energy value of an offer is capped at $2,000/MWh.

(b) Demand Bids shall not specify a bid price below the Energy Offer Floor or above the Demand Bid Cap.

(c) Supply Offers shall not specify an offer price (for incremental energy) below the Energy Offer Floor.

(d) External Transactions shall not specify a price below the External Transaction Floor or above the External Transaction Cap.

(e) Increment Offers and Decrement Bids shall not specify an offer or bid price below the Energy Offer Floor or above the Virtual Cap.

III.1.9.2 [Reserved.]

III.1.9.3 [Reserved.]

III.1.9.4 [Reserved.]

III.1.9.5 [Reserved.]

III.1.9.6 [Reserved.]

III.1.9.7 Market Participant Responsibilities.

Market Participants authorized and intending to request market-based Start-Up Fees and No-Load Fee in their Offer Data shall submit a specification of such fees to the ISO for each Generator Asset as to which the Market Participant intends to request such fees. Any such specification shall identify the applicable period and be submitted on or before the applicable deadline and shall remain in effect unless otherwise modified in accordance with Section III.1.10.9. The ISO shall reject any request for Start-Up Fees and No-Load Fee in a Market Participant's Offer Data that does not conform to the Market Participant's specification on file with the ISO.

III.1.9.8 [Reserved.]

III.1.10 Scheduling.

III.1.10.1 General.

(a) The ISO shall administer scheduling processes to implement a Day-Ahead Energy Market and a Real-Time Energy Market.

(b) The Day-Ahead Energy Market shall enable Market Participants to purchase and sell energy and, commencing on June 1, 2024, sell ancillary services through the New England Markets at the applicable Day-Ahead Prices, and enable Market Participants to submit External Transactions conditioned upon Congestion Costs not exceeding a specified level. Market Participants whose purchases and sales and External Transactions are scheduled in the Day-Ahead Energy Market shall be obligated to purchase or sell energy or pay Congestion Costs and costs for losses, at the applicable Day-Ahead Prices for the amounts scheduled.

(c) In the Real-Time Energy Market,

(i) Market Participants that deviate from the amount of energy purchases or sales scheduled in the Day-Ahead Energy Market shall replace the energy not delivered with energy from the Real-Time Energy Market or an internal bilateral transaction and shall pay for such energy not delivered, net of any internal bilateral transactions, at the applicable Real-Time Price, unless otherwise specified by this Market Rule 1, and

(ii) Non-Market Participant Transmission Customers shall be obligated to pay Congestion Costs and costs for losses for the amount of the scheduled transmission uses in the Real-Time Energy Market at the applicable Real-Time Congestion Component and Loss Component price differences, unless otherwise specified by this Market Rule 1.

(d) The following scheduling procedures and principles shall govern the commitment of Resources to the Day-Ahead Energy Market and the Real-Time Energy Market over a period extending from one week to one hour prior to the Real-Time dispatch. Scheduling encompasses the Day-Ahead and hourly scheduling process, through which the ISO determines the Day-Ahead Energy Market schedule and determines, based on changing forecasts of conditions and actions by Market Participants and system constraints, a plan to serve the hourly energy and reserve requirements of the New England Control Area in the least costly manner, subject to maintaining the reliability of the New England Control Area. Scheduling of External Transactions in the Real-Time Energy Market is subject to Section II.44 of the OATT.

(e) If the ISO's forecast for the next seven days projects a likelihood of Emergency Condition, the ISO may commit, for all or part of such seven day period, to the use of Generator Assets or Demand Response Resources with Notification Time greater than 24 hours as necessary in order to alleviate or mitigate such Emergency, in accordance with the Market Participants' binding Supply Offers or Demand Reduction Offers.

III.1.10.1A Energy Market Scheduling.

The submission of Day-Ahead offers and bids shall occur not later than 10:00 a.m. on the day before the Operating Day for which transactions are being scheduled, or such other deadline as may be specified by the ISO in order to comply with the practical requirements and the economic and efficiency objectives of the scheduling process specified in this Market Rule 1.

(a) **Locational Demand Bids –** Each Market Participant may submit to the ISO specifications of the amount and location of its customer loads and/or energy purchases to be included in the Day-Ahead Energy Market for each hour of the next Operating Day, such specifications to comply with the requirements set forth in the ISO New England Manuals and ISO New England Administrative Procedures. Each Market Participant shall inform the ISO of (i) the prices, if any, at which it desires not to include its load in the Day-Ahead Energy Market rather than pay the applicable Day-Ahead Price, (ii) hourly schedules for Resources Self-Scheduled by the Market Participant; and (iii) the Decrement Bid at which each such Self-Scheduled Resource will disconnect or reduce output, or confirmation of the Market Participant's intent not to reduce output. Price-sensitive Demand Bids and Decrement Bids must be greater than zero MW and shall not exceed the Demand Bid Cap and Virtual Cap.

(b) **External Transactions –** All Market Participants shall submit to the ISO schedules for any External Transactions involving use of Generator Assets or the New England Transmission System as specified below, and shall inform the ISO whether the transaction is to be included in the Day-Ahead Energy Market. Any Market Participant that elects to include an External Transaction in the Day-Ahead Energy Market may specify the price (such price not to exceed the maximum price that may be specified in the ISO New England Manuals and ISO New England Administrative Procedures), if any, at which it will be curtailed rather than pay Congestion Costs. The foregoing price specification shall apply to the price difference between the Locational Marginal Prices for specified External Transaction source and sink points in the Day-Ahead scheduling process only. Any Market Participant that deviates from its Day-Ahead External Transaction schedule or elects not to include its External Transaction in the Day-Ahead Energy Market shall be subject to Congestion Costs in the Real-Time Energy Market in order to complete any such scheduled External Transaction. Scheduling of External Transactions shall be conducted in accordance with the specifications in the ISO New England Manuals and ISO New England Administrative Procedures and the following requirements:

(i) Market Participants shall submit schedules for all External Transaction purchases for delivery within the New England Control Area from Resources outside the New England Control Area;

(ii) Market Participants shall submit schedules for External Transaction sales to entities outside the New England Control Area from Resources within the New England Control Area;

(iii) In the Day-Ahead Energy Market, if the sum of all submitted Self-Scheduled External Transaction purchases less External Transaction sales exceeds the import capability associated with the applicable External Node, the offer prices for all Self-Scheduled External Transaction purchases at the applicable External Node shall be set equal to the Energy Offer Floor;

(iv) In the Day-Ahead Energy Market, if the sum of all submitted Self-Scheduled External Transaction sales less External Transaction purchases exceeds the export capability associated with the applicable External Node, the offer prices for all Self-Scheduled External Transaction sales at the applicable External Node shall be set equal to the External Transaction Cap;

(v) The ISO shall not consider Start-Up Fees, No-Load Fees, Notification Times or any other inter-temporal parameters in scheduling or dispatching External Transactions.

(c) **Generator Asset Supply Offers –** Market Participants selling into the New England Markets from Generator Assets may submit Supply Offers for the supply of energy for the following Operating Day.

Such Supply Offers:

(i) Shall specify the Resource and Blocks (price and quantity of Energy) for each hour of the Operating Day for each Resource offered by the Market Participant to the ISO. The prices and quantities in a Block may each vary on an hourly basis;

(ii) If based on energy from a Generator Asset internal to the New England Control Area, may specify, for Supply Offers, a Start-Up Fee and No-Load Fee for each hour of the Operating Day. Start-Up Fee and No-Load Fee may vary on an hourly basis;

(iii) Shall specify, for Supply Offers from a dual-fuel Generator Asset, the fuel type. The fuel type may vary on an hourly basis. A Market Participant that submits a Supply Offer using the higher cost fuel type must satisfy the consultation requirements for dual-fuel Generator Assets in Section III.A.3 of Appendix A;

(iv) Shall specify a Minimum Run Time to be used for commitment purposes that does not exceed 24 hours;

(v) Supply Offers shall constitute an offer to submit the Generator Asset to the ISO for commitment and dispatch in accordance with the terms of the Supply Offer, where such Supply Offer, with regard to operating limits, shall specify changes, including to the Economic Maximum Limit, Economic Minimum Limit and Emergency Minimum Limit, from those submitted as part of the Resource's Offer Data to reflect the physical operating characteristics and/or availability of the Resource (except that for a Limited Energy Resource, the Economic Maximum Limit may be revised to reflect an energy (MWh) limitation), which offer shall remain open through the Operating Day for which the Supply Offer is submitted; and

(vi) Shall, in the case of a Supply Offer from a Generator Asset associated with an Electric Storage Facility, also meet the requirements specified in Section III.1.10.6.

(d) DARD Demand Bids – Market Participants participating in the New England Markets with Dispatchable Asset Related Demands may submit Demand Bids for the consumption of energy for the following Operating Day.

Such Demand Bids:

(i) Shall specify the Dispatchable Asset Related Demand and Blocks (price and Energy quantity pairs) for each hour of the Operating Day for each Dispatchable Asset Related Demand offered by the Market Participant to the ISO. The prices and quantities in a Block may each vary on an hourly basis;

(ii) Shall constitute an offer to submit the Dispatchable Asset Related Demand to the ISO for commitment and dispatch in accordance with the terms of the Demand Bid, where such Demand Bid, with regard to operating limits, shall specify changes, including to the Maximum Consumption Limit and Minimum Consumption Limit, from those submitted as part of the Resource's Offer Data to reflect the physical operating characteristics and/or availability of the Resource;

(iii) Shall specify a Minimum Consumption Limit that is less than or equal to its Nominated Consumption Limit; and

(iv) Shall, in the case of a Demand Bid from a Storage DARD, also meet the requirements specified in Section III.1.10.6.

(e) **Demand Response Resource Demand Reduction Offers –** Market Participants selling into the New England Markets from Demand Response Resources may submit Demand Reduction Offers for the supply of energy for the following Operating Day. A Demand Reduction Offer shall constitute an offer to submit the Demand Response Resource to the ISO for commitment and dispatch in accordance with the terms of the Demand Reduction Offer. Demand Reduction Offers:

(i) Shall specify the Demand Response Resource and Blocks (price and demand reduction quantity pairs) for each hour of the Operating Day. The prices and demand reduction quantities may vary on an hourly basis.

(ii) Shall not specify a price that is above the Energy Offer Cap, below the Energy Offer Floor, or below the Demand Reduction Threshold Price in effect for the Operating Day. For purposes of clearing the Day-Ahead and Real-Time Energy Markets and calculating Day-Ahead and Real-Time Locational Marginal Prices and Real-Time Reserve Clearing Prices, any price specified below the Demand Reduction Threshold price in effect for the Operating Day will be considered to be equal to the Demand Reduction Threshold Price for the Operating Day.

(iii) Shall not include average avoided peak transmission or distribution losses in the demand reduction quantity.

(iv) May specify an Interruption Cost for each hour of the Operating Day, which may vary on an hourly basis.

(v) Shall specify a Minimum Reduction Time to be used for scheduling purposes that does not exceed 24 hours.

(vi) Shall specify a Maximum Reduction amount no greater than the sum of the Maximum Interruptible Capacities of the Demand Response Resource's operational Demand Response Assets.

(vii) Shall specify changes to the Maximum Reduction and Minimum Reduction from those submitted as part of the Demand Response Resource's Offer Data to reflect the physical operating characteristics and/or availability of the Demand Response Resource.

(f) **Demand Reduction Threshold Price –** The Demand Reduction Threshold Price for each month shall be determined through an analysis of a smoothed, historic supply curve for the month. The historic supply curve shall be derived from Real-Time generator and import Offer Data (excluding Coordinated External Transactions) for the same month of the previous year. The ISO may adjust the Offer Data to account for significant changes in generator and import availability or other significant changes to the historic supply curve. The historic supply curve shall be calculated as follows:

(a) Each generator and import offer Block (i.e., each price-quantity pair offered in the Real-Time Energy Market) for each day of the month shall be compiled and sorted in ascending order of price to create an unsmoothed supply curve.

(b) An unsmoothed supply curve for the month shall be formed from the price and cumulative quantity of each offer Block.

(c) A non-linear regression shall be performed on a sampled portion of the unsmoothed supply curve to produce an increasing, convex, smooth approximation of the supply curve.

(d) A historic threshold price P_{th} shall be determined as the point on the smoothed supply curve beyond which the benefit to load from the reduced LMP resulting from the demand reduction of Demand Response Resources exceeds the cost to load associated with compensating Demand Response Resources for demand reduction.

(e) The Demand Reduction Threshold Price for the upcoming month shall be determined by the following formula:

$$DRTP = P_{th} X — \frac{FPI_c}{FPI_h}$$

where FPI_h is the historic fuel price index for the same month of the previous year, and FPI_c is the fuel price index for the current month.

The historic and current fuel price indices used to establish the Demand Reduction Threshold Price for a month shall be based on the lesser of the monthly natural gas or heating oil fuel indices applicable to the New England Control Area, as calculated three business days before the start of the month preceding the Demand Reduction Threshold Price's effective date.

The ISO will post the Demand Reduction Threshold Price, along with the index-based fuel price values used in establishing the Demand Reduction Threshold Price, on its website by the 15^{th} day of the month preceding the Demand Reduction Threshold Price's effective date.

(g) **Subsequent Operating Days** – Each Supply Offer, Demand Reduction Offer, or Demand Bid by a Market Participant of a Resource shall remain in effect for subsequent Operating Days until superseded or canceled except in the case of an External Transaction purchase, in which case, the Supply Offer shall remain in effect for the applicable Operating Day and shall not remain in effect for subsequent Operating Days. Hourly overrides of a Supply Offer, a Demand Reduction Offer, or a Demand Bid shall remain in effect only for the applicable Operating Day.

(h) **Load Estimate** – The ISO shall post on the internet the total hourly loads including Decrement Bids scheduled in the Day-Ahead Energy Market, as well as the ISO's estimate of the Control Area hourly load for the next Operating Day.

(i) **Prorated Supply** – In determining Day-Ahead schedules, in the event of multiple marginal Supply Offers, Demand Reduction Offers, Increment Offers and/or External Transaction purchases at a pricing location, the ISO shall clear the marginal Supply Offers, Demand Reduction Offers, Increment Offers and/or External Transaction purchases proportional to the amount of energy (MW) from each marginal offer and/or External Transaction at the pricing location. The Economic Maximum Limits, Economic Minimum Limits, Minimum Reductions and Maximum Reductions are not used in determining the amount of energy (MW) in each marginal Supply Offer or Demand Reduction Offer to be cleared on a pro-rated basis. However, the Day-Ahead schedules resulting from the pro-ration process will reflect Economic Maximum Limits, Economic Minimum Limits, Minimum Reductions and Maximum Reductions.

(j) **Prorated Demand** – In determining Day-Ahead schedules, in the event of multiple marginal Demand Bids, Decrement Bids and/or External Transaction sales at a pricing location, the ISO shall clear the marginal Demand Bids, Decrement Bids and/or External Transaction sales proportional to the amount of energy (MW) from each marginal bid and/or External Transaction at the pricing location.

(k) **Virtuals** – All Market Participants may submit Increment Offers and/or Decrement Bids that apply to the Day-Ahead Energy Market only. Such offers and bids must comply with the requirements set forth in the ISO New England Manuals and ISO New England Administrative Procedures and must specify amount, location and price, if any, at which the Market Participant desires to purchase or sell energy in the Day-Ahead Energy Market.

(l) **Energy Call Option Offers –** Market Participants selling into the New England Markets from Generator Assets or Demand Response Resources may submit Energy Call Option Offers for the following Operating Day. Energy Call Option Offers shall be submitted to the ISO in accordance with Section III.1.8.2 of this Market Rule 1.

III.1.10.2 Pool-Scheduled Resources.

Pool-Scheduled Resources are those Resources for which Market Participants submitted Supply Offers, Demand Reduction Offers, or Demand Bids in the Day-Ahead Energy Market and which the ISO scheduled in the Day-Ahead Energy Market as well as Generator Assets, DARDs or Demand Response Resources committed by the ISO subsequent to the Day-Ahead Energy Market. Such Resources shall be committed to provide or consume energy in the Real-Time dispatch unless the schedules for such Resources are revised pursuant to Sections III.1.10.9 or III.1.11. Pool-Scheduled Resources shall be governed by the following principles and procedures.

(a) Pool-Scheduled Resources shall be selected by the ISO on the basis of the prices offered for energy supply or consumption and related services, Start-Up Fees, No-Load Fees, Interruption Cost and the specified operating characteristics, offered by Market Participants.

(b) The ISO shall optimize the dispatch of energy, and commencing on June 1, 2024, energy and ancillary services, from Limited Energy Resources by request to minimize the as-bid production cost for the New England Control Area. In implementing the use of Limited Energy Resources, the ISO shall use its best efforts to select the most economic hours of operation for Limited Energy Resources, in order to make optimal use of such Resources in the Day-Ahead Energy Market consistent with the Supply Offers and Demand Reduction Offers of other Resources, the submitted Demand Bids and Decrement Bids, and ancillary services requirements procured pursuant to this Market Rule 1.

(c) Market Participants offering energy from facilities with fuel or environmental limitations may submit data to the ISO that is sufficient to enable the ISO to determine the available operating hours of such facilities.

(d) Market Participants shall make available their Pool-Scheduled Resources to the ISO for coordinated operation to supply the needs of the New England Control Area for energy and ancillary services.

III.1.10.3 Self-Scheduled Resources.

A Resource that is Self-Scheduled shall be governed by the following principles and procedures. The minimum duration of a Self-Schedule for a Generator Asset or DARD shall not result in the Generator Asset or DARD operating for less than its Minimum Run Time. A Generator Asset that is online as a result of a Self-Schedule will be dispatched above its Economic Minimum Limit based on the economic merit of its Supply Offer. A DARD that is consuming as a result of a Self-Schedule may be dispatched above its Minimum Consumption Limit based on the economic merit of its Demand Bid. A Demand Response Resource shall not be Self-Scheduled.

III.1.10.4 External Resources.

Market Participants with External Resources may submit External Transactions as detailed in Section III.1.10.7 and Section III.1.10.7.A of this Market Rule 1.

III.1.10.5 Dispatchable Asset Related Demand.

(a) External Transactions that are sales to an external Control Area are not eligible to be Dispatchable Asset Related Demands.

(b) A Market Participant with a Dispatchable Asset Related Demand in the New England Control Area must:

(i) notify the ISO of any outage (including partial outages) that may reduce the Dispatchable Asset Related Demand's ability to respond to Dispatch Instructions and the expected return date from the outage;

(ii) in accordance with the ISO New England Manuals and Operating Procedures, perform audit tests and submit the results to the ISO or provide to the ISO appropriate historical production data;

(iii) abide by the ISO maintenance coordination procedures; and

(iv) provide information reasonably requested by the ISO, including the name and location of the Dispatchable Asset Related Demand.

III.1.10.6 Electric Storage

A storage facility is a facility that is capable of receiving electricity from the grid and storing the energy for later injection of electricity back to the grid. A storage facility may participate in the New England Markets as described below.

(a) A storage facility that satisfies the requirements of this subsection (a) may participate in the New England Markets as an Electric Storage Facility. An Electric Storage Facility shall:

(i) comprise one or more storage facilities at the same point of interconnection;

(ii) have the ability to inject at least 0.1 MW and consume at least 0.1 MW;

(iii) be directly metered;

(iv) be registered as, and subject to all rules applicable to, a dispatchable Generator Asset;

(v) be registered as, and subject to all rules applicable to, a DARD that represents the same equipment as the Generator Asset;

(vi) settle its injection of electricity to the grid as a Generator Asset and its receipt of electricity from the grid as a DARD;

(vii) not be precluded from providing retail services so long as it is able to fulfill its wholesale Energy Market and Forward Capacity Market obligations including, but not limited to, satisfying meter data reporting requirements and notifying the ISO of any changes to operational capabilities; and

(viii) meet the requirements of either a Binary Storage Facility or a Continuous Storage Facility, as described in subsections (b) and (c) below.

(b) A storage facility that satisfies the requirements of this subsection (b) may participate in the New England Markets as a Binary Storage Facility. A Binary Storage Facility shall:

- (i) satisfy the requirements applicable to an Electric Storage Facility; and
- (ii) offer its Generator Asset and DARD into the Energy Market as Rapid Response Pricing Assets; and
- (iii) be issued Dispatch Instructions in a manner that ensures the facility is not required to consume and inject simultaneously.

(c) A storage facility that satisfies the requirements of this subsection (c) may participate in the New England Markets as a Continuous Storage Facility. A Continuous Storage Facility shall:

- (i) satisfy the requirements applicable to an Electric Storage Facility;
- (ii) be registered as, may provide Regulation as, and is subject to all rules applicable to, an ATRR that represents the same equipment as the Generator Asset and DARD;
- (iii) be capable of transitioning between the facility's maximum output and maximum consumption (and vice versa) in ten minutes or less;
- (iv) not utilize storage capability that is shared with another Generator Asset, DARD or ATRR;
- (v) specify in Supply Offers a zero MW value for Economic Minimum Limit and Emergency Minimum Limit (except for Generator Assets undergoing Facility and Equipment Testing or auditing); a zero time value for Minimum Run Time, Minimum Down Time, Notification Time, and Start-Up Time; and a zero cost value for Start-Up Fee and No-Load Fee;
- (vi) specify in Demand Bids a zero MW value for Minimum Consumption Limit (except for DARDs undergoing Facility and Equipment Testing or auditing) and a zero time value for Minimum Run Time and Minimum Down Time;
- (vii) be Self-Scheduled in the Day-Ahead Energy Market and Real-Time Energy Market, and operate in an on-line state, unless the facility is declared unavailable by the Market Participant; and
- (viii) be issued a combined dispatch control signal equal to the Desired Dispatch Point (of the Generator Asset) minus the Desired Dispatch Point (of the DARD) plus the AGC SetPoint (of the ATRR).

(d) A storage facility shall comply with all applicable registration, metering, and accounting rules including, but not limited to, the following:

(i) A Market Participant wishing to purchase energy from the ISO-administered wholesale markets must first, jointly with its Host Participant, register one or more wholesale Load Assets with the ISO as described in ISO New England Manual M-28 and ISO New England Manual M-RPA; where the Market Participant wishes to register an Electric Storage Facility, the registered Load Asset must be a DARD.

(ii) A storage facility's charging load shall not qualify as a DARD if the Host Participant is unwilling or unable to support the registration, metering, and accounting of the storage facility's load as a separate and distinct Load Asset. A storage facility registered as a DARD will be charged the nodal Locational Marginal Price by the ISO and the Market Participant will not pay twice for the same charging load.

(iii) The registration and metering of all Assets must comply with ISO New England Operating Procedure No. 14 and ISO New England Operating Procedure No. 18, including with the requirement that an Asset's revenue metering must comply with the accuracy requirements found in ISO New England Operating Procedure No. 18.

(iv) Pursuant to ISO New England Manual M-28, the Assigned Meter Reader, the Host Participant, and the ISO provide the data for use in the daily settlement process within the timelines described in the manual. The data may be five-minute interval data, and may be no more than hourly data, as described in Section III.3.2 and in ISO New England Manual M-28.

(v) Based on the Metered Quantity For Settlement and the Locational Marginal Price in the settlement interval, the ISO shall conduct all Energy Market accounting pursuant to Section III.3.2.1.

(e) A facility registered as a dispatchable Generator Asset, an ATRR, and a DARD that each represent the same equipment must participate as a Continuous Storage Facility.

(f) A storage facility not participating as an Electric Storage Facility may, if it satisfies the associated requirements, be registered as a Generator Asset (including a Settlement Only Resource) for settlement of its injection of electricity to the grid and as an Asset Related Demand for settlement of its wholesale load.

(g) A storage facility may, if it satisfies the associated requirements, be registered as a Demand Response Asset. (As described in Section III.8.1.1, a Demand Response Asset and a Generator Asset may not be registered at the same end-use customer facility unless the Generator Asset is separately metered and reported and its output does not reduce the load reported at the Retail Delivery Point of the Demand Response Asset.)

(h) A storage device may, if it satisfies the associated requirements, be registered as a component of either an On-Peak Demand Resource or a Seasonal Peak Demand Resource.

(i) A storage facility may, if it satisfies the associated requirements, provide Regulation pursuant to Section III.14.

III.1.10.7 External Transactions.

The provisions of this Section III.1.10.7 do not apply to Coordinated External Transactions.

(a) Market Participants that submit an External Transaction in the Day-Ahead Energy Market must also submit a corresponding External Transaction in the Real-Time Energy Market in order to be eligible for scheduling in the Real-Time Energy Market. Priced External Transactions for the Real-Time Energy Market must be submitted by the offer submission deadline for the Day-Ahead Energy Market.

(b) Priced External Transactions submitted in both the Day-Ahead Energy Market and the Real-Time Energy Market will be treated as Self-Scheduled External Transactions in the Real-Time Energy Market for the associated megawatt amounts that cleared the Day-Ahead Energy Market, unless the Market Participant modifies the price component of its Real-Time offer during the Re-Offer Period.

(c) Any External Transaction, or portion thereof, submitted to the Real-Time Energy Market that did not clear in the Day-Ahead Energy Market will not be scheduled in Real-Time if the ISO anticipates that the External Transaction would create or worsen an Emergency. External Transactions cleared in the Day-Ahead Energy Market and associated with a Real-Time Energy Market submission will continue to be scheduled in Real-Time prior to and during an Emergency, until the procedures governing the Emergency, as set forth in ISO New England Operating Procedure No. 9, require a change in schedule.

(d) External Transactions submitted to the Real-Time Energy Market must contain the associated e-Tag ID and transmission reservation, if required, at the time the transaction is submitted to the Real-Time Energy Market.

(e) [Reserved.]

(f) External Transaction sales meeting all of the criteria for any of the transaction types described in (i) through (iv) below receive priority in the scheduling and curtailment of transactions as set forth in Section II.44 of the OATT. External Transaction sales meeting all of the criteria for any of the transaction types described in (i) through (iv) below are referred to herein and in the OATT as being supported in Real-Time.

(i) Capacity Export Through Import Constrained Zone Transactions:

(1) The External Transaction is exporting across an external interface located in an import-constrained Capacity Zone that cleared in the Forward Capacity Auction with price separation, as determined in accordance with Section III.12.4 and Section III.13.2.3.4 of Market Rule 1;

(2) The External Transaction is directly associated with an Export Bid or Administrative Export De-List Bid that cleared in the Forward Capacity Auction, and the megawatt amount of the External Transaction is less than or equal to the megawatt amount of the cleared Export Bid;

(3) The External Node associated with the cleared Export Bid or Administrative Export De-List Bid is connected to the import-constrained Capacity Zone, and is not connected to a Capacity Zone that is not import-constrained;

(4) The Resource, or portion thereof, that is associated with the cleared Export Bid or Administrative Export De-List Bid is not located in the import-constrained Capacity Zone;

(5) The External Transaction has been submitted and cleared in the Day-Ahead Energy Market;

(6) A matching External Transaction has also been submitted into the Real-Time Energy Market by the end of the Re-Offer Period for Self-Scheduled External Transactions, and, in accordance with Section III.1.10.7(a), by the offer submission deadline for the Day-Ahead Energy Market for priced External Transactions.

(ii) FCA Cleared Export Transactions:

(1) The External Transaction sale is exporting to an External Node that is connected only to an import-constrained Reserve Zone;

(2) The External Transaction sale is directly associated with an Export Bid or an Administrative Export De-List Bid that cleared in the Forward Capacity Auction, and the megawatt amount of the External Transaction is less than or equal to the megawatt amount of the cleared Export Bid;

(3) The Resource, or portion thereof, without a Capacity Supply Obligation associated with the Export Bid or Administrative Export De-List Bid is located outside the import-constrained Reserve Zone;

(4) The External Transaction sale is submitted and cleared in the Day-Ahead Energy Market;

(5) A matching External Transaction has also been submitted into the Real-Time Energy Market by the end of the Re-Offer Period for Self-Scheduled External Transactions, and, in accordance with Section III.1.10.7(a), by the offer submission deadline for the Day-Ahead Energy Market for priced External Transactions.

(iii) Same Reserve Zone Export Transactions:

(1) A Resource, or portion thereof, without a Capacity Supply Obligation is associated with the External Transaction sale, and the megawatt amount of the External Transaction is less than or equal to the portion of the Resource without a Capacity Supply Obligation;

(2) The External Node of the External Transaction sale is connected only to the same Reserve Zone in which the associated Resource, or portion thereof, without a Capacity Supply Obligation is located;

(3) The Resource, or portion thereof, without a Capacity Supply Obligation is Self-Scheduled in the Real-Time Energy Market and online at a megawatt level greater than or equal to the External Transaction sale’s megawatt amount;

(4) Neither the External Transaction sale nor the portion of the Resource without a Capacity Supply Obligation is required to offer into the Day-Ahead Energy Market.

(iv) Unconstrained Export Transactions:

(1) A Resource, or portion thereof, without a Capacity Supply Obligation is associated with the External Transaction sale, and the megawatt amount of the External Transaction is less than or equal to the portion of the Resource without a Capacity Supply Obligation;

(2) The External Node of the External Transaction sale is not connected only to an import-constrained Reserve Zone;

(3) The Resource, or portion thereof, without a Capacity Supply Obligation is not separated from the External Node by a transmission interface constraint as determined in Sections III.12.2.1(b) and III.12.2.2(b) of Market Rule 1 that was binding in the Forward Capacity Auction in the direction of the export;

(4) The Resource, or portion thereof, without a Capacity Supply Obligation is Self-Scheduled in the Real-Time Energy Market and online at a megawatt level greater than or equal to the External Transaction sale's megawatt amount;

(5) Neither the External Transaction sale, nor the portion of the Resource without a Capacity Supply Obligation is required to offer into the Day-Ahead Energy Market.

(g) Treatment of External Transaction sales in ISO commitment for local second contingency protection.

(i) Capacity Export Through Import Constrained Zone Transactions and FCA Cleared Export Transactions: The transaction's export demand that clears in the Day-Ahead Energy Market will be explicitly considered as load in the exporting Reserve Zone by the ISO when committing Resources to provide local second contingency protection for the associated Operating Day.

(ii) The export demand of External Transaction sales not meeting the criteria in (i) above is not considered by the ISO when planning and committing Resources to provide local second contingency protection, and is assumed to be zero.

(iii) Same Reserve Zone Export Transactions and Unconstrained Export Transactions: If a Resource, or portion thereof, without a Capacity Supply Obligation is committed to be online during the Operating Day either through clearing in the Day-Ahead Energy Market or through Self-Scheduling subsequent to the Day-Ahead Energy Market and a Same Reserve Zone Export Transaction or Unconstrained Export Transaction is submitted before the end of the Re-Offer Period designating that Resource as supporting the transaction, the ISO will not utilize the portion of the Resource without a Capacity Supply Obligation supporting the export transaction to meet local second contingency protection requirements. The eligibility of Resources not meeting the foregoing criteria to be used to meet local second contingency protection requirements shall be in accordance with the relevant provisions of the ISO New England System Rules.

(h) Allocation of costs to Capacity Export Through Import Constrained Zone Transactions and FCA Cleared Export Transactions: Market Participants with Capacity Export Through Import Constrained Zone Transactions and FCA Cleared Export Transactions shall incur a proportional share of the charges described below, which are allocated to Market Participants based on Day-Ahead Load Obligation or Real-Time Load Obligation. The share shall be determined by including the Day-Ahead Load Obligation or Real-Time Load Obligation associated with the External Transaction, as applicable, in the total Day-Ahead Load Obligation or Real-Time Load Obligation for the appropriate Reliability Region, Reserve Zone, or Load Zone used in each cost allocation calculation:

(i) NCPC for Local Second Contingency Protection Resources allocated within the exporting Reliability Region, pursuant to Section III.F.3.3.

(ii) Forward Reserve Market charges allocated within the exporting Load Zone, pursuant to Section III.9.9.

(iii) Real-Time Reserve Charges allocated within the exporting Load Zone, pursuant to Section III.10.3.

(i) When action is taken by the ISO to reduce External Transaction sales due to a system wide capacity deficient condition or the forecast of such a condition, and an External Transaction sale designates a Resource, or portion of a Resource, without a Capacity Supply Obligation, to support the transaction, the ISO will review the status of the designated Resource. If the designated Resource is Self-Scheduled and online at a megawatt level greater than or equal to the External Transaction sale, that External Transaction sale will not be reduced until such time as Regional Network Load within the New England Control Area is also being reduced. When reductions to such transactions are required, the affected transactions shall be reduced pro-rata.

(j) Market Participants shall submit External Transactions as megawatt blocks with intervals of one hour at the relevant External Node. External Transactions will be scheduled in the Day-Ahead Energy Market as megawatt blocks for hourly durations. The ISO may dispatch External Transactions in the Real-Time Energy Market as megawatt blocks for periods of less than one hour, to the extent allowed pursuant to inter-Control Area operating protocols.

III.1.10.7.A Coordinated Transaction Scheduling.

The provisions of this Section III.1.10.7.A apply to Coordinated External Transactions, which are implemented at the New York Northern AC external Location.

(a) Market Participants that submit a Coordinated External Transaction in the Day-Ahead Energy Market must also submit a corresponding Coordinated External Transaction, in the form of an Interface Bid, in the Real-Time Energy Market in order to be eligible for scheduling in the Real-Time Energy Market.

(b) An Interface Bid submitted in the Real-Time Energy Market shall specify a duration consisting of one or more consecutive 15-minute increments. An Interface Bid shall include a bid price, a bid quantity, and a bid direction for each 15-minute increment. The bid price may be positive or negative. An Interface Bid may not be submitted or modified later than 75 minutes before the start of the clock hour for which it is offered.

(c) Interface Bids are cleared in economic merit order for each 15-minute increment, based upon the forecasted real-time price difference across the external interface. The total quantity of Interface Bids cleared shall determine the external interface schedule between New England and the adjacent Control Area. The total quantity of Interface Bids cleared shall depend upon, among other factors, bid production costs of resources in both Control Areas, the Interface Bids of all Market Participants, transmission system conditions, and any real-time operating limits necessary to ensure reliable operation of the transmission system.

(d) All Coordinated External Transactions submitted either to the Day-Ahead Energy Market or the Real-Time Energy Market must contain the associated e-Tag ID at the time the transaction is submitted.

(e) Any Coordinated External Transaction, or portion thereof, submitted to the Real-Time Energy Market will not be scheduled in Real-Time if the ISO anticipates that the External Transaction would create or worsen an Emergency, unless the procedures governing the Emergency, as set forth in ISO New England Operating Procedure No. 9, permit the transaction to be scheduled.

III.1.10.8 ISO Responsibilities.

(a) Scheduling Considerations

(i) Prior to June 1, 2024, the ISO shall use its best efforts to determine (1) the least-cost means of satisfying hourly purchase requests for energy, the projected hourly requirements for Operating Reserve, Replacement Reserve and other ancillary services of the Market Participants, including the reliability requirements of the New England Control Area, of the Day-Ahead Energy Market, and (2) the least-cost means of satisfying the Operating Reserve, Replacement Reserve and other ancillary service requirements for any portion of the load forecast of the ISO for the Operating Day in excess of that scheduled in the Day-Ahead Energy Market.

In making the determinations specified in this subsection (a)(i), the ISO shall take into account: (i) the ISO's forecasts of New England Markets and New England Control Area energy requirements, giving due consideration to the energy requirement forecasts and purchase requests submitted by Market Participants for the Day-Ahead Energy Market; (ii) the offers and bids submitted by Market Participants; (iii) the availability of Limited Energy Resources; (iv) the capacity, location, and other relevant characteristics of Self-Scheduled Resources; (v) the requirements of the New England Control Area for Operating Reserve and Replacement Reserve, as specified in the ISO New England Manuals and ISO New England Administrative Procedures; (vi) the requirements of the New England Control Area for Regulation and other ancillary services, as specified in the ISO New England Manuals and ISO New England Administrative Procedures; (vii) the benefits of avoiding or minimizing transmission constraint control operations, as specified in the ISO New England Manuals and ISO New England Administrative Procedures; and (viii) such other factors as the ISO reasonably concludes are relevant to the foregoing determination. The ISO shall develop a Day-Ahead Energy schedule based on the applicable portions of the foregoing determination, and shall determine the Day-Ahead Prices resulting from such schedule.

(ii) Commencing on June 1, 2024, in scheduling the Day-Ahead Energy Market, the ISO shall use its best efforts to determine the security-constrained economic commitment and dispatch that jointly optimizes: (1) Demand Bids, Decrement Bids, Demand Reduction Offers, Supply Offers, Increment Offers, and External Transactions, for energy; (2) Energy Call Option Offers to satisfy the Day-Ahead Ancillary Services demand quantities; and (3) Supply Offers, Demand Reduction Offers, External Transactions, and Energy Call Option Offers to satisfy the Forecast Energy Requirement Demand Quantity.

In making the determinations specified in this subsection (a)(ii), the ISO shall take into account, as applicable: (1) the ISO's forecasts of New England Markets and New England Control Area energy requirements, giving due consideration to the energy requirement forecasts and purchase requests submitted by Market Participants for the Day-Ahead Energy Market; (2) the offers and bids submitted by Market Participants; (3) the availability of Limited Energy Resources; (4) capacity, location, and other relevant characteristics of Self-Scheduled Resources; (5) the requirements of the New England Control Area for ancillary services; (6) the operational capabilities of any Resource to adjust the output, consumption, or demand reduction within the operating characteristics specified in the Market Participant's Offer Data, Supply Offer, Demand Reduction Offer, or Demand Bid; (7) the benefits of avoiding or minimizing transmission constraint control operations, as specified in the ISO New England Manuals and ISO New England Administrative Procedures; and (8) such other factors as the ISO reasonably concludes are relevant to the foregoing determination.

In scheduling the Day-Ahead Energy Market, the following limitations shall apply:

(1) For purposes of satisfying the demand quantities for Day-Ahead Generation Contingency Reserve or Day-Ahead Replacement Energy Reserve specified in Sections III.1.8.5(a)-(e), the ISO shall not take into account an Energy Call Option Offer unless the Generator Asset or the Demand Response Resource associated with the Energy Call Option Offer meets the eligibility requirements enumerated in Section III.1.7.19.1.

(2) For purposes of satisfying the Day-Ahead Energy Imbalance Reserve Demand Quantity specified in Section III.1.8.5(f), the ISO shall not take into account an Energy Call

Option Offer unless the Generator Asset or the Demand Response Resource associated with the Energy Call Option Offer is either (i) scheduled for energy in the Day-Ahead Energy Market for the applicable hour, or (ii) is a Fast Start Generator or Fast Start Demand Response Resource.

(b) Not later than 1:30 p.m. of the day before each Operating Day, or such earlier deadline as may be specified by the ISO in the ISO New England Manuals and ISO New England Administrative Procedures or such later deadline as necessary to account for software failures or other events, the ISO shall: (i) post the aggregate Day-Ahead Energy schedule; (ii) post the Day-Ahead Prices; and (iii) inform the Market Participants of their scheduled injections and withdrawals. In the event of an Emergency, the ISO will notify Market Participants as soon as practicable if the Day-Ahead Energy Market cannot be operated.

(c) Following posting of the information specified in Section III.1.10.8(b), the ISO shall revise its schedule of Resources to reflect updated projections of load, conditions affecting electric system operations in the New England Control Area, the availability of and constraints on limited energy and other Resources, transmission constraints, and other relevant factors. The ISO shall use its best efforts to determine the least-cost means to satisfy any remaining reliability requirements of the New England Control Area for the Operating Day.

(d) Market Participants shall pay and be paid for the quantities of energy scheduled in the Day-Ahead Energy Market at the applicable Day-Ahead Prices.

III.1.10.9 Hourly Scheduling.

(a) Following the initial posting by the ISO of the Locational Marginal Prices resulting from the Day-Ahead Energy Market, and subject to the right of the ISO to schedule and dispatch Resources and to direct that schedules be changed to address an actual or potential Emergency, a Resource Re-Offer Period shall exist from the time of the posting specified in Section III.1.10.8(b) until 2:00 p.m. on the day before each Operating Day or such other Re-Offer Period as necessary to account for software failures or other events. During the Re-Offer Period, Market Participants may submit revisions to Supply Offers, revisions to Demand Reduction Offers, and revisions to Demand Bids for any Dispatchable Asset Related Demand. Resources scheduled subsequent to the closing of the Re-Offer Period shall be settled at the applicable Real-Time Prices, and shall not affect the obligation to pay or receive payment for the quantities of energy scheduled in the Day-Ahead Energy Market at the applicable Day-Ahead Prices.

(b) During the Re-Offer Period, Market Participants may submit revisions to the price of priced External Transactions. External Transactions scheduled subsequent to the closing of the Re-Offer Period shall be settled at the applicable Real-Time Prices, and shall not affect the obligation to pay or receive payment for the quantities of energy scheduled in the Day-Ahead Energy Market at the applicable Day-Ahead Prices. A submission during the Re-Offer Period for any portion of a transaction that was cleared in the Day-Ahead Energy Market is subject to the provisions in Section III.1.10.7. A Market Participant may request to Self-Schedule an External Transaction and adjust the schedule on an hour-to-hour basis or request to reduce the quantity of a priced External Transaction. The ISO must be notified of the request not later than 60 minutes prior to the hour in which the adjustment is to take effect. The External Transaction re-offer provisions of this Section III.1.10.9(b) shall not apply to Coordinated External Transactions, which are submitted pursuant to Section III.1.10.7.A.

(c) Following the completion of the initial Reserve Adequacy Analysis and throughout the Operating Day, a Market Participant may modify certain Supply Offer or Demand Bid parameters for a Generator Asset or a Dispatchable Asset Related Demand on an hour-to-hour basis, provided that the modification is made no later than 30 minutes prior to the beginning of the hour for which the modification is to take effect:

(i) For a Generator Asset, the Start-Up Fee, the No-Load Fee, the fuel type (for dual-fuel Generator Assets), and the quantity and price pairs of its Blocks may be modified.

(ii) For a Dispatchable Asset Related Demand, the quantity and price pairs of its Blocks may be modified.

(d) Following the completion of the initial Reserve Adequacy Analysis and throughout the Operating Day, a Market Participant may not modify any of the following Demand Reduction Offer parameters: price and demand reduction quantity pairs, Interruption Cost, Demand Response Resource Start-Up Time, Demand Response Resource Notification Time, Minimum Reduction Time, and Minimum Time Between Reductions.

(e) During the Operating Day, a Market Participant may request to Self-Schedule a Generator Asset or Dispatchable Asset Related Demand or may request to cancel a Self-Schedule for a Generator Asset or Dispatchable Asset Related Demand. The ISO will honor the request so long as it will not cause or worsen a reliability constraint. If the ISO is able to honor a Self-Schedule request, a Generator Asset will be permitted to come online at its Economic Minimum Limit and a Dispatchable Asset Related Demand will be dispatched to its Minimum Consumption Limit. A Market Participant may not request to Self-

Schedule a Demand Response Resource. A Market Participant may cancel the Self-Schedule of a Continuous Storage Generator Asset or a Continuous Storage DARD only by declaring the facility unavailable.

(f) During the Operating Day, in the event that in a given hour a Market Participant seeks to modify a Supply Offer or Demand Bid after the deadline for modifications specified in Section III.1.10.9(c), then:

(i) the Market Participant may request that a Generator Asset be dispatched above its Economic Minimum Limit at a specified output. The ISO will honor the request so long as it will not cause or worsen a reliability constraint. If the ISO is able to honor the request, the Generator Asset will be dispatched as though it had offered the specified output for the hour in question at the Energy Offer Floor.

(ii) the Market Participant may request that a Dispatchable Asset Related Demand be dispatched above its Minimum Consumption Limit at a specified value. The ISO will honor the request so long as it will not cause or worsen a reliability constraint. If the ISO is able to honor the request, the Dispatchable Asset Related Demand will be dispatched at or above the requested amount for the hour in question.

(g) During the Operating Day, in any interval in which a Generator Asset is providing Regulation, the upper limit of its energy dispatch range shall be reduced by the amount of Regulation Capacity, and the lower limit of its energy dispatch range shall be increased by the amount of Regulation Capacity. Any such adjustment shall not affect the Real-Time Reserve Designation.

(h) During the Operating Day, in any interval in which a Continuous Storage ATRR is providing Regulation, the upper limit of the associated Generator Asset's energy dispatch range shall be reduced by the Regulation High Limit, and the associated DARD's consumption dispatch range shall be reduced by the Regulation Low Limit. Any such adjustment shall not affect the Real-Time Reserve Designation.

(i) For each hour in the Operating Day, as soon as practicable after the deadlines specified in the foregoing subsection of this Section III.1.10, the ISO shall provide Market Participants and parties to External Transactions with any revisions to their schedules for the hour.

III.1.11 Dispatch.

The following procedures and principles shall govern the dispatch of the Resources available to the ISO.

III.1.11.1 Resource Output or Consumption and Demand Reduction.

The ISO shall have the authority to direct any Market Participant to adjust the output, consumption or demand reduction of any Dispatchable Resource within the operating characteristics specified in the Market Participant's Offer Data, Supply Offer, Demand Reduction Offer or Demand Bid. The ISO may cancel its selection of, or otherwise release, Pool-Scheduled Resources. The ISO shall adjust the output, consumption or demand reduction of Resources as necessary: (a) for both Dispatchable Resources and Non-Dispatchable Resources, to maintain reliability, and subject to that constraint, for Dispatchable Resources, (b) to minimize the cost of supplying the energy, reserves, and other services required by the Market Participants and the operation of the New England Control Area; (c) to balance supply and demand, maintain scheduled tie flows, and provide frequency support within the New England Control Area; and (d) to minimize unscheduled interchange that is not frequency related between the New England Control Area and other Control Areas.

III.1.11.2 Operating Basis.

In carrying out the foregoing objectives, the ISO shall conduct the operation of the New England Control Area and shall, in accordance with the ISO New England Manuals and ISO New England Administrative Procedures, (i) utilize available Operating Reserve and replace such Operating Reserve when utilized; and (ii) monitor the availability of adequate Operating Reserve.

III.1.11.3 Dispatchable Resources.

With the exception of Settlement Only Resources, Generator Assets that meet the size criteria to be Settlement Only Resources, External Transactions, nuclear-powered Resources and photovoltaic Resources, all Resources must be Dispatchable Resources in the Energy Market and meet the technical specifications in ISO New England Operating Procedure No. 14 and ISO New England Operating Procedure No. 18 for dispatchability.

A Market Participant that does not meet the requirement for a Dispatchable Resource to be dispatchable in the Energy Market because the Resource is not connected to a remote terminal unit meeting the requirements of ISO New England Operating Procedure No. 18 shall take the following steps:

1. By January 15, 2017, the Market Participant shall submit to the ISO a circuit order form for the primary and secondary communication paths for the remote terminal unit.

2. The Market Participant shall work diligently with the ISO to ensure the Resource is able to receive and respond to electronic Dispatch Instructions within twelve months of the circuit order form submission.

A Market Participant that does not meet the requirement for a Dispatchable Resource to be dispatchable in the Energy Market by the deadline set forth above shall provide the ISO with a written plan for remedying the deficiencies, and shall identify in the plan the specific actions to be taken and a reasonable timeline for rendering the Resource dispatchable. The Market Participant shall complete the remediation in accordance with and under the timeline set forth in the written plan. Until a Resource is dispatchable, it may only be Self-Scheduled in the Real-Time Energy Market and shall otherwise be treated as a Non-Dispatchable Resource.

Dispatchable Resources in the Energy Market are subject to the following requirements:

(a) The ISO shall optimize the dispatch of energy from Limited Energy Resources by request to minimize the as-bid production cost for the New England Control Area. In implementing the use of Limited Energy Resources, the ISO shall use its best efforts to select the most economic hours of operation for Limited Energy Resources, in order to make optimal use of such Resources consistent with the dynamic load-following requirements of the New England Control Area and the availability of other Resources to the ISO.

(b) The ISO shall implement the dispatch of energy from Dispatchable Resources and the designation of Real-Time Operating Reserve to Dispatchable Resources, including the dispatchable portion of Resources which are otherwise Self-Scheduled, by sending appropriate signals and instructions to the entity controlling such Resources. Each Market Participant shall ensure that the entity controlling a Dispatchable Resource offered or made available by that Market Participant complies with the energy dispatch signals and instructions transmitted by the ISO.

(c) The ISO shall have the authority to modify a Market Participant's operational related Offer Data for a Dispatchable Resource if the ISO observes that the Market Participant's Resource is not operating in accordance with such Offer Data. The ISO shall modify such operational related Offer Data based on observed performance and such modified Offer Data shall remain in effect until either (i) the affected Market Participant requests a test to be performed, and coordinates the testing pursuant to the procedures specified in the ISO New England Manuals, and the results of the test justify a change to the Market Participant's Offer Data or (ii) the ISO observes, through actual performance, that modification to the Market Participant's Offer Data is justified.

(d) Market Participants shall exert all reasonable efforts to operate, or ensure the operation of, their Dispatchable Resources in the New England Control Area as close to dispatched output, consumption or demand reduction levels as practical, consistent with Good Utility Practice.

(e) Settlement Only Resources are not eligible to be DNE Dispatchable Generators.

Wind and hydro Intermittent Power Resources that are not Settlement Only Resources are required to receive and respond to Do Not Exceed Dispatch Points, except as follows:

(i) A wind or hydro Intermittent Power Resource not capable of receiving and responding to electronic Dispatch Instructions will be manually dispatched.

(ii) A Market Participant may elect, but is not required, to have a wind or hydro Intermittent Power Resource that is less than 5 MW and is connected through transmission facilities rated at less than 115 kV be dispatched as a DNE Dispatchable Generator.

(iii) A Market Participant with a hydro Intermittent Power Resource that is able to operate within a dispatchable range and is capable of responding to Dispatch Instructions to increase or decrease output within its dispatchable range may elect to have that resource dispatched as a DDP Dispatchable Resource.

(f) The ISO may request that dual-fuel Generator Assets that normally burn natural gas voluntarily take all necessary steps (within the limitations imposed by the operating limitations of their installed equipment and their environmental and operating permits) to prepare to switch to secondary fuel in anticipation of natural gas supply shortages. The ISO may request that Market Participants with dual-fuel Generator Assets that normally burn natural gas voluntarily switch to a secondary fuel in anticipation of natural gas supply shortages. The ISO may communicate with Market Participants with dual-fuel Generator Assets that normally burn natural gas to verify whether the Market Participants have switched or are planning to switch to an alternate fuel.

III.1.11.4 Emergency Condition.

If the ISO anticipates or declares an Emergency Condition, all External Transaction sales out of the New England Control Area that are not backed by a Resource may be interrupted, in accordance with the ISO New England Manuals, in order to serve load and Operating Reserve in the New England Control Area.

III.1.11.5 Dispatchability Requirements for Intermittent Power Resources.

(a) Intermittent Power Resources that are Dispatchable Resources with Supply Offers that do not clear in the Day-Ahead Energy Market and are not committed by the ISO prior to or during the Operating Day must be Self-Scheduled in the Real-Time Energy Market at the Resource's Economic Minimum Limit in order to operate in Real-Time.

(b) Intermittent Power Resources that are not Settlement Only Resources, are not Dispatchable Resources, and are not committed by the ISO prior to or during the Operating Day must be Self-Scheduled in the Real-Time Energy Market with the Resource's Economic Maximum Limit and Economic Minimum Limit redeclared to the same value in order to operate in Real-Time. Redeclarations must be updated throughout the Operating Day to reflect actual operating capabilities.

III.1.11.6 Non-Dispatchable Resources.

Non-Dispatchable Resources are subject to the following requirements:

(a) The ISO shall have the authority to modify a Market Participant's operational related Offer Data for a Non-Dispatchable Resource if the ISO observes that the Market Participant's Resource is not operating in accordance with such Offer Data. The ISO shall modify such operational related Offer Data based on observed performance and such modified Offer Data shall remain in effect until either (i) the affected Market Participant requests a test to be performed and coordinates the testing pursuant to the procedures specified in the ISO New England Manuals, and the results of the test justify a change to the Market Participant's Offer Data or (ii) the ISO observes, through actual performance, that modification to the Market Participant's Offer Data is justified.

(b) Market Participants with Non-Dispatchable Resources shall exert all reasonable efforts to operate or ensure the operation of their Resources in the New England Control Area as close to dispatched levels as practical when dispatched by the ISO for reliability, consistent with Good Utility Practice.

III.2 Day-Ahead Prices, Real-Time Prices, and Real-Time Reserve Clearing Prices Calculation

III.2.1 Introduction.

The ISO shall calculate the price of energy at Nodes, Load Zones, DRR Aggregation Zones and Hubs in the New England Control Area and at External Nodes on the basis of Locational Marginal Prices and shall calculate the price of Operating Reserve in Real-Time for each Reserve Zone on the basis of Real-Time Reserve Clearing Prices as determined in accordance with this Market Rule 1. Locational Marginal Prices for energy shall be calculated on a Day-Ahead basis for each hour of the Day-Ahead Energy Market, and every five minutes during the Operating Day for the Real-Time Energy Market. Real-Time Reserve Clearing Prices shall be calculated on a Real-Time basis every five minutes as part of the joint optimization of energy and Operating Reserve during the Operating Day. Commencing on June 1, 2024, Day-Ahead Ancillary Services prices and the Forecast Energy Requirement Price shall be calculated for each hour of the Operating Day, as specified in Section III.2.6.2, as part of the joint optimization of energy and ancillary services in the Day-Ahead Energy Market.

III.2.2 General.

The ISO shall determine the least cost security-constrained unit commitment and dispatch, which is the least costly means of serving load at different Locations in the New England Control Area based on scheduled or actual conditions, as applicable, existing on the power grid and on the prices at which Market Participants have offered to supply and consume energy in the New England Markets. Day-Ahead Locational Marginal Prices for energy for the applicable Locations will be calculated based on the unit commitment and economic dispatch and the prices of offers and bids. Real-Time Locational Marginal Prices for energy and Real-Time Reserve Clearing Prices will be calculated based on a jointly optimized economic dispatch of energy and designation of Operating Reserve utilizing the prices of energy offers and bids, and Reserve Constraint Penalty Factors as specified in Section III.2.7A when applicable. Commencing on June 1, 2024, Day-Ahead Locational Marginal Prices for energy, Day-Ahead Ancillary Services prices, and the Forecast Energy Requirement Price will be calculated based on a jointly optimized security-constrained economic commitment and dispatch of energy and Day-Ahead Ancillary Services utilizing the prices of offers and bids, and Reserve Constraint Penalty Factors as specified in Section III.2.6.2(b) when applicable.

Except as further provided in Section III.2.6, the process for the determination of Locational Marginal Prices shall be as follows:

(a) To determine operating conditions, in the Day-Ahead Energy Market or Real-Time Energy Market, on the New England Transmission System, the ISO shall use a computer model of the interconnected grid that uses scheduled quantities or available metered inputs regarding electric output, loads, and power flows to model remaining flows and conditions, producing a consistent representation of power flows on the network. The computer model employed for this purpose in the Real-Time Energy Market, referred to as the State Estimator program, is a standard industry tool and is described in Section III.2.3. It will be used to obtain information regarding the output of resources supplying energy and Operating Reserve to the New England Control Area, loads at busses in the New England Control Area, transmission losses, penalty factors, and power flows on binding transmission and interface constraints for use in the calculation of Day-Ahead and Real-Time Locational Marginal Prices and Real-Time Reserve Clearing Prices, and, commencing on June 1, 2024, Day-Ahead Ancillary Services prices and the Forecast Energy Requirement Price. Additional information used in the calculation of Real-Time Locational Marginal Prices and Real-Time Reserve Clearing Prices, including Offer Data, Real-Time Operating Reserve designations and Real-Time schedules for External Transactions, will be obtained from the ISO's dispatch software and dispatchers.

(b) Using the prices at which Market Participants offer and bid energy to the New England Markets, the ISO shall determine the offers and bids of energy that will be considered in the calculation of Day-Ahead Prices, Real-Time Prices and Real-Time Reserve Clearing Prices. During the Operating Day, Real-Time nodal Locational Marginal Prices and Real-Time Reserve Clearing Prices shall be determined every five minutes and such determinations shall be the basis of the settlement of sales and purchases of energy in the Real-Time Energy Market, the settlement associated with the provision of Operating Reserve in Real-Time and the settlement of Congestion Costs and costs for losses under the Transmission, Markets and Services Tariff not covered by the Day-Ahead Energy Market. As described in Section III.2.6, every offer and bid by a Market Participant that is scheduled in the Day-Ahead Energy Market will be utilized in the calculation of Day-Ahead Locational Marginal Prices.

III.2.3 Determination of System Conditions Using the State Estimator.

Power system operations, including, but not limited to, the determination of the least costly means of serving load and system and zonal Real-Time Operating Reserve requirements, depend upon the availability of a complete and consistent representation of generator outputs, loads, and power flows on the network. In calculating Day-Ahead Prices, the ISO shall base the system conditions on the expected transmission system configuration and the set of offers and bids submitted by Market Participants. In

calculating Real-Time Locational Marginal Prices and Real-Time Reserve Clearing Prices, the ISO shall obtain a complete and consistent description of conditions on the electric network in the New England Control Area by using the power flow solution produced by the State Estimator for the pricing interval, which is also used by the ISO for other functions within power system operations. The State Estimator is a standard industry tool that produces a power flow model based on available Real-Time metering information, information regarding the current status of lines, generators, transformers, and other equipment, bus load distribution factors, and a representation of the electric network, to provide a complete description of system conditions, including conditions at Nodes and External Nodes for which Real-Time information is unavailable. In calculating Real-Time Locational Marginal Prices and Real-Time Reserve Clearing Prices, the ISO shall obtain a State Estimator solution every five minutes, which shall provide the megawatt output of generators and the loads at Locations in the New England Control Area, transmission line losses, penalty factors, and actual flows or loadings on constrained transmission facilities. External Transactions between the New England Control Area and other Control Areas shall be included in the Real-Time Locational Marginal Price calculation on the basis of the Real-Time transaction schedules implemented by the ISO's dispatcher.

III.2.4 Adjustment for Rapid Response Pricing Assets.

For any Real-Time pricing interval during which a Rapid Response Pricing Asset is committed by the ISO, is in a dispatchable mode, and is not Self-Scheduled, the energy offer of that Rapid Response Pricing Asset shall be adjusted as described in this Section III.2.4 for purposes of the price calculations described in Section III.2.5 and Section III.2.7A. For purposes of the adjustment described in this Section III.2.4, if no Start-Up Fee, No-Load Fee, or Interruption Cost is specified in the submitted Offer Data, a value of zero shall be used; if no Minimum Run Time or Minimum Reduction Time is specified in the submitted Offer Data, or if the submitted Minimum Run Time or Minimum Reduction Time is less than 15 minutes, a duration of 15 minutes shall be used; and the energy offer after adjustment shall not exceed $2,000/MWh.

(a) If the Rapid Response Pricing Asset is a Fast Start Generator or a Flexible DNE Dispatchable Generator, its Economic Minimum Limit shall be set to zero; if the Rapid Response Pricing Asset is a Binary Storage DARD, its Minimum Consumption Limit shall be set to zero; if the Rapid Response Pricing Asset is a Fast Start Demand Response Resource, its Minimum Reduction shall be set to zero.

(b) If the Rapid Response Pricing Asset is a Fast Start Generator or a Flexible DNE Dispatchable Generator that has not satisfied its Minimum Run Time, its energy offer shall be increased by: (i) the

Start-Up Fee divided by the product of the Economic Maximum Limit and the Minimum Run Time; and (ii) the No-Load Fee divided by the Economic Maximum Limit.

(c) If the Rapid Response Pricing Asset is a Fast Start Generator or a Flexible DNE Dispatchable Generator that has satisfied its Minimum Run Time, its energy offer shall be increased by the No-Load Fee divided by the Economic Maximum Limit.

(d) If the Rapid Response Pricing Asset is a Fast Start Demand Response Resource that has not satisfied its Minimum Reduction Time, its energy offer shall be increased by the Interruption Cost divided by the product of the Maximum Reduction and the Minimum Reduction Time.

(e) If the Rapid Response Pricing Asset is a Fast Start Demand Response Resource that has satisfied its Minimum Reduction Time, its energy offer shall not be increased.

III.2.5 Calculation of Nodal Real-Time Prices.

(a) The ISO shall determine the least costly means of obtaining energy to serve the next increment of load at each Node internal to the New England Control Area represented in the State Estimator and each External Node Location between the New England Control Area and an adjacent Control Area, based on the system conditions described by the power flow solution produced by the State Estimator for the pricing interval. This calculation shall be made by applying an optimization method to minimize energy cost, given actual system conditions, a set of energy offers and bids (adjusted as described in Section III.2.4), and any binding transmission and Operating Reserve constraints that may exist. In performing this calculation, the ISO shall calculate the cost of serving an increment of load at each Node and External Node from all available Generator Assets (excluding Settlement Only Resources), Demand Response Resources, External Transaction purchases submitted under Section III.1.10.7 and Dispatchable Asset Related Demands with an eligible energy offer as the sum of: (1) the price at which the Market Participant has offered to supply or consume an additional increment of energy from the Resource; (2) the effect on Congestion Costs (whether positive or negative) associated with increasing the output of the Resource or reducing consumption of the Resource, based on the effect of increased output from that Resource or reduced consumption from that Resource on transmission line loadings; and (3) the effect on Congestion Costs (whether positive or negative) associated with increasing the Operating Reserve requirement, based on the effect of Resource re-dispatch on transmission line loadings; (4) the effect on Congestion Costs (whether positive or negative) associated with a deficiency in Operating Reserve, based on the effect of the Reserve Constraint Penalty Factors described under Section III.2.7A(c); and (5) the

effect on transmission losses caused by the increment of load, generation and demand reduction. The energy offer or offers and energy bid or bids that can jointly serve an increment of load and an increment of Operating Reserve requirement at a Location at the lowest cost, calculated in this manner, shall determine the Real-Time Price at that Node or External Node. For an external interface for which the enhanced scheduling procedures in Section III.1.10.7.A are implemented, the Real-Time Price at the External Node shall be further adjusted to include the effect on Congestion Costs (whether positive or negative) associated with a binding constraint limiting the external interface schedule, as determined when the interface is scheduled.

(b) During the Operating Day, the calculation set forth in this Section III.2.5 shall be performed for every five-minute interval, using the ISO's Locational Marginal Price program, producing a set of nodal Real-Time Prices based on system conditions during the pricing interval. The prices produced at five-minute intervals during an hour will be integrated to determine the nodal Real-Time Prices for that hour.

(c) For any interval during any hour in the Operating Day that the ISO has declared a Minimum Generation Emergency, the affected nodal Real-Time Prices calculated under this Section III.2.5 shall be set equal to the Energy Offer Floor for all Nodes within the New England Control Area and all External Nodes.

III.2.6 Calculation of Day-Ahead Prices.

III.2.6.1 Calculation of Day-Ahead Locational Marginal Prices.

(a) For the Day-Ahead Energy Market, Day-Ahead Locational Marginal Prices shall be determined on the basis of the least-cost, security-constrained unit commitment and dispatch, model flows and system conditions resulting from the load specifications submitted by Market Participants, Supply Offers, Demand Reduction Offers and Demand Bids for Resources, Increment Offers, Decrement Bids, External Transactions, and, commencing on June 1, 2024, the Forecast Energy Requirement Demand Quantity, Day-Ahead Ancillary Service demand quantities, and Energy Call Option Offers submitted to the ISO and scheduled in the Day-Ahead Energy Market.

Such prices shall be determined in accordance with the provisions of this Section applicable to the Day-Ahead Energy Market and shall be the basis for the settlement of purchases and sales of energy, costs for losses and Congestion Costs resulting from the Day-Ahead Energy Market. This calculation shall be made for each hour in the Day-Ahead Energy Market by applying an optimization method to minimize

energy and, commencing on June 1, 2024, ancillary services cost, given scheduled system conditions, scheduled transmission outages, and any transmission limitations that may exist. In performing this calculation, the ISO shall calculate the cost of serving an increment of load at each Node and External Node from each Resource associated with an eligible energy offer, energy bid, or Energy Call Option Offer as the sum of: (1) the price at which the Market Participant has offered to supply an additional increment of energy from the Resource or reduce consumption from the Resource and, commencing on June 1, 2024, the effect on ancillary service costs associated with increasing the output of the Resource or reducing consumption of the Resource; (2) the effect on transmission Congestion Costs (whether positive or negative) associated with increasing the output of the Resource or reducing consumption of the Resource, based on the effect of increased output from that Resource or reduced consumption from a Resource on transmission line loadings; and (3) the effect on transmission losses caused by the increment of load and supply. The energy offer or offers, Energy Call Option Offer or offers, and energy bid or bids that can serve an increment of load at a Node or External Node at the lowest cost, calculated in this manner, shall determine the Day-Ahead Locational Marginal Price at that Node.

For External Nodes for which the enhanced scheduling procedures in Section III.1.10.7.A are implemented, the clearing process specified in the previous two paragraphs shall apply. For all other External Nodes, the following process shall apply: in addition to determining the quantity cleared via the application of transmission constraints (i.e., limits on the flow over a line or set of lines), the quantity cleared is limited via the application of a nodal constraint (i.e., a limit on the total net injections at a Node) that restricts the net amount of cleared transactions to the transfer capability of the external interface. Clearing prices at all Nodes will reflect the marginal cost of serving the next increment of load at that Node while reflecting transmission constraints. A binding nodal constraint will result in interface limits being followed, but will not directly affect the congestion component of an LMP at an External Node.

(b) Energy deficient conditions. If the sum of Day-Ahead fixed Demand Bids and fixed External Transaction sales cannot be satisfied with the sum of all scheduled External Transaction purchases, cleared Increment Offers, and available supply at the Generator Asset’s Economic Maximum Limit and demand reduction at the Demand Response Resource’s Maximum Reduction, the technical software issues an Emergency Condition warning message due to a shortage of economic supply in the Day-Ahead Energy Market. The following steps shall then be performed to achieve power balance:

(i) All fixed External Transaction sales are considered to be dispatchable at the External Transaction Cap;

(ii) Reduce any remaining price-sensitive Demand Bids (including External Transaction sales) and Decrement Bids from lowest price to highest price to zero MW until power balance is achieved (there may be some price sensitive bids that are higher priced than the highest Supply Offer, Demand Reduction Offer, or Increment Offer price cleared). Set LMP values equal to the highest price-sensitive Demand Bid or Decrement Bid that was cut in this step. If no price-sensitive Demand Bid or Decrement Bid was reduced in this step, the LMP values are set equal to highest offer price of all on-line Generator Assets, dispatched Demand Response Resources, Increment Offers or External Transaction purchases; and

(iii) If power balance is not achieved after step (ii), reduce all remaining fixed Demand Bids proportionately (by ratio of load MW) until balance is achieved. Set LMP values equal to the highest offer price of all on-line Generator Assets (excluding Settlement Only Resources), dispatched Demand Response Resources, Increment Offers or External Transaction purchases or the price from step (ii), whichever is higher.

(c) Excess energy conditions. If the sum of Day-Ahead cleared Demand Bids, Decrement Bids and External Transaction sales is less than the total system wide supply (including fixed External Transaction purchases) with all possible Generator Assets off line and with all remaining Generator Assets at their Economic Minimum Limit, the technical software issues a Minimum Generation Emergency warning message due to an excess of economic supply in the Day-Ahead Energy Market. The following steps shall then be performed to achieve power balance:

(i) All fixed External Transaction purchases are considered to be dispatchable at the Energy Offer Floor and reduced pro-rata, as applicable, until power balance is reached;

(ii) If power balance is not reached in step (i), reduce all committed Generator Assets down proportionately by ratio of Economic Minimum Limits, but not below Emergency Minimum Limits. If power balance is achieved prior to reaching Emergency Minimum Limits, set LMP values equal to the lowest offer price of all on-line Generator Assets (excluding Settlement Only Resources); and

(iii) If power balance not achieved in step (ii), set LMP values to Energy Offer Floor and reduce all Generator Assets generation below Emergency Minimum Limits proportionately (by ratio of Emergency Minimum Limits) to achieve power balance.

III.2.6.2 Calculation of Additional Day-Ahead Prices.

(a) Commencing on June 1, 2024, the ISO shall calculate hourly Day-Ahead Prices for additional requirements in the Day-Ahead Energy Market as described in this Section III.2.6.2(a).

(i) The clearing price for Day-Ahead Four-Hour Reserve shall be the incremental cost, as measured by the change in the Day-Ahead Energy Market's security-constrained economic dispatch objective value, to satisfy the next increment of the Day-Ahead Total Four-Hour Reserve Demand Quantity.

(ii) The clearing price for Day-Ahead Ninety-Minute Reserve shall be the sum of (a) the incremental cost, as measured by the change in the Day-Ahead Energy Market's security-constrained economic dispatch objective value, to satisfy the next increment of the Day-Ahead Total Ninety-Minute Reserve Demand Quantity, and (b) the clearing price for Day-Ahead Four-Hour Reserve.

(iii) The clearing price for Day-Ahead Thirty-Minute Operating Reserve shall be the sum of (a) the incremental cost, as measured by the change in the Day-Ahead Energy Market's security-constrained economic dispatch objective value, to satisfy the next increment of the Day-Ahead Total Thirty-Minute Operating Reserve Demand Quantity, and (b) the clearing price for Day-Ahead Ninety-Minute Reserve.

(iv) The clearing price for Day-Ahead Ten-Minute Non-Spinning Reserve shall be the sum of (a) the incremental cost, as measured by the change in the Day-Ahead Energy Market's security-constrained economic dispatch objective value, to satisfy the next increment of the Day-Ahead Total Ten-Minute Reserve Demand Quantity, and (b) the clearing price for Day-Ahead Thirty-Minute Operating Reserve.

(v) The clearing price for Day-Ahead Ten-Minute Spinning Reserve shall be the sum of (a) the incremental cost, as measured by the change in the Day-Ahead Energy Market's security-constrained economic dispatch objective value, to satisfy the next increment of the Day-Ahead

Ten-Minute Spinning Reserve Demand Quantity, and (b) the clearing price for Day-Ahead Ten-Minute Non-Spinning Reserve.

(vi) The clearing price for Day-Ahead Energy Imbalance Reserve shall be the Forecast Energy Requirement Price.

(vii) The Forecast Energy Requirement Price shall be the marginal cost, as measured by the change in the Day-Ahead Energy Market's security-constrained economic dispatch objective value, to satisfy the next increment of the Forecast Energy Requirement Demand Quantity.

(b) **Reserve Constraint Penalty Factors.** The Day-Ahead Energy Market scheduling pursuant to Section III.1.10.8(a)(ii), and the Day-Ahead Prices specified in Section III.2.6, shall respect the applicable Reserve Constraint Penalty Factors specified below:

(i) The Reserve Constraint Penalty Factor applicable to the Day-Ahead Ten-Minute Spinning Reserve Demand Quantity shall be equal to the Real-Time Ten-Minute Spinning Reserve Requirement Reserve Constraint Penalty Factor specified in Section III.2.7A.

(ii) The Reserve Constraint Penalty Factor applicable to the Day-Ahead Total Ten-Minute Reserve Demand Quantity shall be equal to the Real-Time Ten-Minute Reserve Requirement Reserve Constraint Penalty Factor specified in Section III.2.7A.

(iii) The Reserve Constraint Penalty Factor applicable to the Day-Ahead Total Thirty-Minute Operating Reserve Demand Quantity shall be equal to the Real-Time Minimum Total Reserve Requirement Reserve Constraint Penalty Factor specified in Section III.2.7A.

(iv) The Reserve Constraint Penalty Factor applicable to the Day-Ahead Total Ninety-Minute Reserve Demand Quantity shall be equal to $250/MWh.

(v) The Reserve Constraint Penalty Factor applicable to the Day-Ahead Total Four-Hour Reserve Demand Quantity shall be equal to $100/MWh.

(vi) The Reserve Constraint Penalty Factor applicable to the Forecast Energy Requirement Demand Quantity shall be set at 101% of the sum of the Reserve Constraint Penalty Factors in Sections III.2.6.2(b)(i)-(v).

III.2.7 Reliability Regions, Load Zones, Reserve Zones, Zonal Prices and External Nodes.

(a) The ISO shall calculate Zonal Prices for each Load Zone and DRR Aggregation Zone for both the Day-Ahead Energy Market and Real-Time Energy Markets using a load-weighted average of the Locational Marginal Prices for the Nodes within that Load Zone or DRR Aggregation Zone. The load weights used in calculating the Day-Ahead Zonal Prices for the Load Zone and DRR Aggregation Zone shall be determined in accordance with applicable Market Rule 1 provisions and shall be based on historical load usage patterns. The load weights do not reflect Demand Bids or Decrement Bids that settle at the Node level in the Day-Ahead Energy Market. The ISO shall determine, in accordance with applicable ISO New England Manuals, the load weights used in Real-Time based on the actual Real-Time load distribution as calculated by the State Estimator, and shall exclude any Asset Related Demand from the load weights used to calculate the applicable Real-Time Zonal Prices.

(b) Each Load Zone shall initially be approximately coterminous with a Reliability Region.

(c) Reserve Zones shall be established by the ISO which represent areas within the New England Transmission System that require local 30 minute contingency response as part of normal system operations in order to satisfy local 2nd contingency response reliability criteria.

(d) The remaining area within the New England Transmission System that is not included within the Reserve Zones established under Section III.2.7(c) is Rest of System.

(e) Each Reserve Zone shall be completely contained within a Load Zone or shall be defined as a subset of the Nodes contained within a Load Zone.

(f) The ISO shall calculate Forward Reserve Clearing Prices and Real-Time Reserve Clearing Prices for each Reserve Zone.

(g) After consulting with the Market Participants, the ISO may reconfigure Reliability Regions, Load Zones, Dispatch Zones, and Reserve Zones and add or subtract Reliability Regions, Load Zones, Dispatch

Zones, and Reserve Zones as necessary over time to reflect changes to the grid, patterns of usage, changes in local TMOR contingency response requirements and intrazonal Congestion. The ISO shall file any such changes with the Commission.

(h) In the event the ISO makes changes to a Reliability Region or Load Zone or adds or subtracts Reliability Regions and Load Zones, for settlement purposes and to the extent practicable, Load Assets that are physically located in one Reliability Region and electrically located within another Reliability Region shall be located within the Reliability Region to which they are electrically located.

(i) External Nodes are the nodes at which External Transactions settle. As appropriate and after consulting with Market Participants, the ISO will establish and re-configure External Nodes taking into consideration appropriate factors, which may include: tie line operational matters, FTR modeling and auction assumptions, market power issues associated with external contractual arrangements, impacts on Locational Marginal Prices, and inter-regional trading impacts.

(j) On or about the 20th calendar day of each month, the ISO shall publish the Real-Time nodal load weights (expressed in MW) used to calculate the load-weighted Real-Time Zonal Prices for the preceding month. Nodal load weights will be published for all nodes used in the calculations except for those nodes identified by customers as nodes for which publication would provide individual customer usage data. Any individual customer whose usage data would be revealed by publication of load weight information associated with a specific Node must submit a written request to the ISO to omit the applicable Node from the publication requirement. The request must identify the affected Node and, to the best of the customer's knowledge, the number of customers taking service at the affected Node and the estimated percentage of the total annual load (MWh) at the affected Node period that is attributable to the customer. The information contained in the request must be certified in writing by an officer of the customer's company (if applicable), by an affidavit signed by a person having knowledge of the applicable facts, or by representation of counsel for the customer. The ISO will grant a customer request if it determines based on the information provided that no more than two customers are taking service at the affected Node or that the percentage of the customer's annual load (MWh) at the affected Node is greater than 75 percent of the total load (MWh) at the affected Node. If a customer request is granted and that customer request is the only such customer request within a Load Zone, then the ISO shall randomly select one other Node and not disclose hourly load information for the randomly selected Node unless and until another customer request within the Load Zone is granted. A request to suspend publication for a month must be received by the ISO on or before the 10th calendar day of the following month in order to be

effective for that month. Upon receipt of a request, the ISO will suspend publication of the load weight data for the specified Node. The ISO may, from time to time, require customer confirmation that continued omission from publication of load weight data for a particular Node is required in order to avoid disclosure of individual customer usage data. If customer confirmation is not received within a reasonable period not to exceed 30 days, the ISO may publish load weight data for the applicable Node.

III.2.7A Calculation of Real-Time Reserve Clearing Prices.

(a) The ISO shall obtain Operating Reserve in Real-Time to serve Operating Reserve requirements for the system and each Reserve Zone on a jointly optimized basis with the calculation of nodal Real-Time Prices specified under Section III.2.5, based on the system conditions described by the power flow solution produced by the State Estimator program for the pricing interval. This calculation shall be made by applying an optimization method to maximize social surplus, given actual system conditions, a set of energy offers and bids, and any binding transmission constraints, including binding transmission interface constraints associated with meeting Operating Reserve requirements, and binding Operating Reserve constraints that may exist. In performing this calculation, the ISO shall calculate, on a jointly optimized basis with serving an increment of load at each Node and External Node, the cost of serving an increment of Operating Reserve requirement for the system and each Reserve Zone from all available Generator Assets (excluding Settlement Only Resources), Demand Response Resources and Dispatchable Asset Related Demands with an eligible energy offer or bid. Real-Time Reserve Clearing Prices will be equal to zero unless system re-dispatch is required in order to meet the system and zonal Operating Reserve requirements or there is a deficiency in available Operating Reserve, in which case Real-Time Reserve Clearing Prices shall be set as described in Section III.2.7A(b) and Section III.2.7A(c).

(b) If system re-dispatch is required to maintain sufficient levels of Operating Reserve, the applicable Real-Time Reserve Clearing Price is equal to the highest unit-specific Real-Time Reserve Opportunity Cost associated with all Generator Assets, Demand Response Resources and Dispatchable Asset Related Demands that were re-dispatched to meet the applicable Operating Reserve requirement. The Real-Time Reserve Opportunity Cost of a Resource shall be equal to the difference between (i) the Real-Time Energy LMP at the Location for the Resource and (ii) the offer price associated with the re-dispatch of the Resource necessary to create the additional Operating Reserve.

(c) If there is insufficient Operating Reserve available to meet the Operating Reserve requirements for the system and/or any Reserve Zone or sufficient Operating Reserve is not available at a redispatch

cost equal to or less than that specified by the Reserve Constraint Penalty Factors, the applicable Real-Time Reserve Clearing Prices shall be set based upon the following Reserve Constraint Penalty Factors:

Real-Time Requirement	**Reserve Constraint Penalty Factor**
Zonal Reserve Requirement (combined amount of TMSR, TMNSR, and TMOR required for a Reserve Zone)	$250/MWh
Minimum Total Reserve Requirement (does not include Replacement Reserve) (combined amount of TMSR, TMNSR, and TMOR required system-wide)	$1000/MWh
Total Reserve Requirement (includes Replacement Reserve) (combined amount of TMSR, TMNSR, and TMOR required system-wide)	$250/MWh
Ten-Minute Reserve Requirement (combined amount of TMSR and TMNSR required system-wide)	$1500/MWh
Ten-Minute Spinning Reserve Requirement (amount of TMSR required system-wide)	$50/MWh

The Reserve Constraint Penalty Factors shall be applied in a manner that is consistent with the price cascading described in Section III.2.7A(d).

(d) Real-Time Reserve designations and Real-Time Reserve Clearing Prices shall be calculated in such a manner to ensure that excess Real-Time Operating Reserve capability will cascade down for use in meeting any remaining Real-Time Operating Reserve requirements from TMSR to TMNSR to TMOR and that the pricing of Real-Time Operating Reserve shall cascade up from TMOR to TMNSR to TMSR.

(e) During the Operating Day, the calculation set forth in this Section III.2.7A shall be performed for every five-minute interval, using the ISO’s Unit Dispatch System and Locational Marginal Price program, producing a set of zonal Real-Time Reserve Clearing Prices based on system conditions for the pricing interval. The prices produced at five-minute intervals during an hour will be integrated to determine the Real-Time Reserve Clearing Prices for the system and/or each Reserve Zone for that hour.

III.2.8 Hubs and Hub Prices.

(a) On behalf of the Market Participants, the ISO shall maintain and facilitate the use of a Hub or Hubs for the Day-Ahead Energy Market and Real-Time Energy Market, comprised of a set of Nodes

within the New England Control Area, which Nodes shall be identified by the ISO on its internet website. The ISO has used the following criteria to establish an initial Hub and shall use the same criteria to establish any additional Hubs:

(i) Each Hub shall contain a sufficient number of Nodes to try to ensure that a Hub Price can be calculated for that Hub at all times;

(ii) Each Hub shall contain a sufficient number of Nodes to ensure that the unavailability of, or an adjacent line outage to, any one Node or set of Nodes would have only a minor impact on the Hub Price;

(iii) Each Hub shall consist of Nodes with a relatively high rate of service availability;

(iv) Each Hub shall consist of Nodes among which transmission service is relatively unconstrained; and

(v) No Hub shall consist of a set of Nodes for which directly connected load and/or generation at that set of Nodes is dominated by any one entity or its Affiliates.

(b) The ISO shall calculate and publish Hub Prices for both the Day-Ahead and Real-Time Energy Markets based upon the arithmetic average of the Locational Marginal Prices of the nodes that comprise the Hub.

III.2.9A Final Real Time Prices, Real-Time Reserve Clearing and Regulation Clearing Prices.

(a) The ISO normally will post provisional Real-Time Prices, Real-Time Reserve Clearing Prices and Regulation clearing prices in Real-Time or soon thereafter. The ISO shall post the final Real-Time Prices, final Real-Time Reserve Clearing Prices and final Regulation clearing prices as soon as practicable following the Operating Day, in accordance with the timeframes specified in the ISO New England Manuals, except that the posting of such final Real-Time Prices, final Real-Time Reserve Clearing Prices and final Regulation clearing prices by the ISO shall not exceed five business days from the applicable Operating Day. If the ISO is not able to calculate Real-Time Prices, Real-Time Reserve Clearing Prices or Regulation clearing prices normally due to human error, hardware, software, or telecommunication problems that cannot be remedied in a timely manner, the ISO will calculate Real-

Time Prices, Real-Time Reserve Clearing Prices or Regulation clearing prices as soon as practicable using the best data available; provided, however, in the event that the ISO is unable to calculate and post final Real-Time Prices, Real-Time Reserve Clearing Prices or Regulation clearing prices due to exigent circumstances not contemplated in this market rule, the ISO shall make an emergency filing with the Commission within five business days from the applicable Operating Day detailing the exigent circumstance, which will not allow the final clearing prices to be calculated and posted, along with a proposed resolution including a timeline to post final clearing prices.

(b) The permissibility of correction of errors in Real-Time Prices, Real-Time Reserve Clearing Prices or Regulation clearing prices for an Operating Day due to database, software or similar errors of the ISO or its systems, and the timeframes and procedures for permitted corrections, are addressed solely in this Section III.2.9A and not in those sections of Market Rule 1 relating to settlement and billing processes.

III.2.9B Final Day-Ahead Energy Market Results

(a) Day-Ahead Energy Market results are final when published except as provided in this subsection. If the ISO determines based on reasonable belief that there may be one or more errors in the Day-Ahead Energy Market results for an Operating Day or if no Day-Ahead Energy Market results are available due to human error, database, software or similar errors of the ISO or its systems, the ISO shall post on the ISO website prior to 12:01 a.m. of the applicable Operating Day, a notice that the results are provisional and subject to correction or unavailable for initial publishing. Any Day-Ahead Energy Market results for which no notice is posted shall be final and not subject to correction or other adjustment, and shall be used for purposes of settlement. The ISO shall confirm within three business days of the close of the applicable Operating Day whether there was an error in any provisional Day-Ahead Energy Market results and shall post a notice stating its findings.

(b) The ISO will publish corrected Day-Ahead Energy Market results within three business days of the close of the applicable Operating Day or the results of the Day-Ahead Energy Market for the Operating Day will stand; provided, however, in the event that the ISO is unable to calculate and post final Day-Ahead Energy Market Results due to exigent circumstances not contemplated in this market rule, the ISO shall make an emergency filing with the Commission within five business days from the applicable Operating Day detailing the exigent circumstance, which will not allow the final prices to be calculated and posted, along with a proposed resolution including a timeline to post final prices. The ISO shall also publish a statement describing the nature of the error and the method used to correct the results.

(c) If the ISO determines in accordance with subsection (a) that there are one or more errors in the Day-Ahead Energy Market results for an Operating Day, the ISO shall calculate corrected Day-Ahead Energy Market results by determining and substituting for the initial results, final results that reasonably reflect how the results would have been calculated but for the errors. To the extent that it is necessary, reasonable and practicable to do so, the ISO may specify an allocation of any costs that are not otherwise allocable under applicable provisions of Market Rule 1. The ISO shall use the corrected results for purposes of settlement.

(d) For every change in the Day-Ahead Energy Market results made pursuant to Section III.2.9B, the ISO will prepare and submit, as soon as practicable, an informational report to the Commission describing the nature of any errors, the precise remedy administered, the method of determining corrected prices and allocating any costs, and any remedial actions that will be taken to avoid similar errors in the future.

(e) The permissibility of correction of errors in Day-Ahead Energy Market results, and the timeframes and procedures for permitted corrections, are addressed solely in this Section III.2.9B and not in those sections of Market Rule 1 relating to settlement and billing processes.

III.3 Accounting And Billing

III.3.1 Introduction.

This Section III.3 sets forth the accounting and billing principles and procedures for the purchase and sale of services in the New England Markets and for the operation of the New England Control Area.

If a dollar-per-MW-hour value is applied in a calculation where the interval of the value produced in that calculation is less than an hour, then for purposes of that calculation the dollar-per-MW-hour value is divided by the number of intervals in the hour.

III.3.2 Market Participants.

III.3.2.1 ISO Energy Market.

For purposes of establishing the following positions, unless otherwise expressly stated, the settlement interval for the Real-Time Energy Market is five minutes and the settlement interval for the Day-Ahead Energy Market is hourly. The Real-Time Energy Market settlement is determined using the Metered Quantity For Settlement calculated in accordance with Section III.3.2.1.1.

(a)(1) **Day-Ahead Energy Market Energy Obligations** – For each Market Participant for each settlement interval, the ISO will determine a Day-Ahead Energy Market position representing that Market Participant's net purchases from or sales to the Day-Ahead Energy Market as follows:

> (i) **Day-Ahead Load Obligation** – Each Market Participant shall have for each settlement interval a Day-Ahead Load Obligation for energy at each Location equal to the MWhs of its Demand Bids, Decrement Bids and External Transaction sales accepted by the ISO in the Day-Ahead Energy Market at that Location and such Day-Ahead Load Obligation shall have a negative value.
>
> (ii) **Day-Ahead Generation Obligation** – Each Market Participant shall have for each settlement interval a Day-Ahead Generation Obligation for energy at each Location equal to the MWhs of its Supply Offers, Increment Offers and External Transaction purchases accepted by the ISO in the Day-Ahead Energy Market at that Location and such Day-Ahead Generation Obligation shall have a positive value.

(iii) **Day-Ahead Demand Reduction Obligation** – Each Market Participant shall have for each settlement interval a Day-Ahead Demand Reduction Obligation at each Location equal to the MWhs of its Demand Reduction Offers accepted by the ISO in the Day-Ahead Energy Market at that Location, increased by average avoided peak distribution losses. Day-Ahead Demand Reduction Obligations shall have a positive value.

(iv) **Day-Ahead Adjusted Load Obligation** – Each Market Participant shall have for each settlement interval a Day-Ahead Adjusted Load Obligation at each Location equal to the Day-Ahead Load Obligation adjusted by any applicable Day-Ahead internal bilateral transactions at that Location.

(v) **Day-Ahead Locational Adjusted Net Interchange** – Each Market Participant shall have for each settlement interval a Day-Ahead Locational Adjusted Net Interchange at each Location equal to the Day-Ahead Adjusted Load Obligation plus the Day-Ahead Generation Obligation plus the Day-Ahead Demand Reduction Obligation at that Location.

(a)(2) **Day-Ahead Energy Market Ancillary Services Obligations** – Commencing on June 1, 2024, each Market Participant with an Energy Call Option Offer that is accepted by the ISO in the Day-Ahead Energy Market shall have for each settlement interval a Day-Ahead Ancillary Services obligation as follows:

(i) **Day-Ahead Ten-Minute Spinning Reserve Obligation** – A Market Participant with an accepted Energy Call Option Offer quantity that contributes to satisfying the Day-Ahead Ten-Minute Spinning Reserve Demand Quantity shall receive a Day-Ahead Ten-Minute Spinning Reserve Obligation.

(ii) **Day-Ahead Ten-Minute Non-Spinning Reserve Obligation** – A Market Participant with an accepted Energy Call Option Offer quantity that contributes to satisfying the Day-Ahead Total Ten-Minute Reserve Demand Quantity, and that same Energy Call Option Offer quantity does not receive a Day-Ahead Ten-Minute Spinning Reserve Obligation, shall receive a Day-Ahead Ten-Minute Non-Spinning Reserve Obligation.

(iii) **Day-Ahead Thirty-Minute Operating Reserve Obligation** – A Market Participant with an accepted Energy Call Option Offer quantity that contributes to satisfying the Day-Ahead Total

Thirty-Minute Operating Reserve Demand Quantity, and that same Energy Call Option Offer quantity does not receive either a Day-Ahead Ten-Minute Spinning Reserve Obligation or a Day-Ahead Ten-Minute Non-Spinning Reserve Obligation, shall receive a Day-Ahead Thirty-Minute Operating Reserve Obligation.

(iv) **Day-Ahead Ninety-Minute Reserve Obligation** – A Market Participant with an accepted Energy Call Option Offer quantity that contributes to satisfying the Day-Ahead Total Ninety-Minute Reserve Demand Quantity, and that same Energy Call Option Offer quantity does not receive a Day-Ahead Ten-Minute Spinning Reserve Obligation, a Day-Ahead Ten-Minute Non-Spinning Reserve Obligation, or a Day-Ahead Thirty-Minute Operating Reserve Obligation, shall receive a Day-Ahead Ninety-Minute Reserve Obligation.

(v) **Day-Ahead Four-Hour Reserve Obligation** – A Market Participant with an accepted Energy Call Option Offer quantity that contributes to satisfying the Day-Ahead Total Four-Hour Reserve Demand Quantity, and that same Energy Call Option Offer quantity does not receive a Day-Ahead Ten-Minute Spinning Reserve Obligation, a Day-Ahead Ten-Minute Non-Spinning Reserve Obligation, a Day-Ahead Thirty-Minute Operating Reserve Obligation, or a Day-Ahead Ninety-Minute Reserve Obligation, shall receive a Day-Ahead Four-Hour Reserve Obligation.

(vi) **Day-Ahead Energy Imbalance Reserve Obligation** – A Market Participant with an accepted Energy Call Option Offer quantity that contributes to satisfying the Forecast Energy Requirement Demand Quantity shall receive a Day-Ahead Energy Imbalance Reserve Obligation.

(b) **Real-Time Energy Market Obligations Excluding Demand Response Resource Contributions** – For each Market Participant for each settlement interval, the ISO will determine a Real-Time Energy Market position. For purposes of these calculations, if the settlement interval is less than one hour, any internal bilateral transaction shall be equally apportioned over the settlement intervals within the hour. To accomplish this, the ISO will perform calculations to determine the following:

(i) **Real-Time Load Obligation** – Each Market Participant shall have for each settlement interval a Real-Time Load Obligation for energy at each Location equal to the MWhs of load, where such MWhs of load shall include External Transaction sales and shall have a negative value, at that Location, adjusted for unmetered load and any applicable internal bilateral transactions which transfer Real-Time load obligations.

(ii) **Real-Time Generation Obligation** – Each Market Participant shall have for each settlement interval a Real-Time Generation Obligation for energy at each Location. The Real-Time Generation Obligation shall equal the MWhs of energy, where such MWhs of energy shall have positive value, provided by Generator Assets and External Transaction purchases at that Location.

(iii) **Real-Time Adjusted Load Obligation** – Each Market Participant shall have for each settlement interval a Real-Time Adjusted Load Obligation at each Location equal to the Real-Time Load Obligation adjusted by any applicable energy related internal Real-Time bilateral transactions at that Location.

(iv) **Real-Time Locational Adjusted Net Interchange –** Each Market Participant shall have for each settlement interval a Real-Time Locational Adjusted Net Interchange at each Location equal to the Real-Time Adjusted Load Obligation plus the Real-Time Generation Obligation at that Location.

(v) **Marginal Loss Revenue Load Obligation –** Each Market Participant shall have for each settlement interval a Marginal Loss Revenue Load Obligation at each Location equal to the Real-Time Load Obligation adjusted by any energy related internal Real-Time bilateral transactions at that Location that the parties to those bilateral transactions have elected to include in their Marginal Loss Revenue Load Obligation for the purpose of allocating Day-Ahead Loss Revenue and Real-Time Loss Revenue. Contributions from Coordinated External Transactions shall be excluded from the Real-Time Load Obligation for purposes of determining Marginal Loss Revenue Load Obligation.

(c) **Real-Time Energy Market Obligations For Demand Response Resources**

Real-Time Demand Reduction Obligation – Each Market Participant shall have for each settlement interval a Real-Time Demand Reduction Obligation at each Location equal to the MWhs of demand reduction provided by Demand Response Resources at that Location in response to non-zero Dispatch Instructions. The MWhs of demand reduction produced by a Demand Response Resource are equal to the sum of the demand reductions produced by its constituent Demand Response Assets calculated pursuant to Section III.8.4, where the demand reductions, other than MWhs associated with Net Supply, are increased by average avoided peak distribution losses.

(d) **Real-Time Energy Market Deviations Excluding Demand Response Resource Contributions** – For each Market Participant for each settlement interval, the ISO will determine the difference between the Real-Time Energy Market position (calculated in accordance with Section III.3.2.1(b)) and the Day-Ahead Energy Market position (calculated in accordance with Section III.3.2.1(a)(1)) representing that Market Participant's net purchases from or sales to the Real-Time Energy Market (excluding any such transactions involving Demand Response Resources). For purposes of this calculation, if the Real-Time settlement interval is less than one hour, the Day-Ahead position shall be equally apportioned over the settlement intervals within the hour. To accomplish this, the ISO will perform calculations to determine the following:

(i) **Real-Time Load Obligation Deviation** – Each Market Participant shall have for each settlement interval a Real-Time Load Obligation Deviation at each Location equal to the difference in MWhs between the Real-Time Load Obligation and the Day-Ahead Load Obligation.

(ii) **Real-Time Generation Obligation Deviation** – Each Market Participant shall have for each settlement interval a Real-Time Generation Obligation Deviation at each Location equal to the difference in MWhs between the Real-Time Generation Obligation and the Day-Ahead Generation Obligation.

(iii) **Real-Time Adjusted Load Obligation Deviation** – Each Market Participant shall have for each settlement interval a Real-Time Adjusted Load Obligation Deviation at each Location equal to the difference in MWhs between the Real-Time Adjusted Load Obligation and the Day-Ahead Adjusted Load Obligation.

(iv) **Real-Time Locational Adjusted Net Interchange Deviation** – Each Market Participant shall have for each settlement interval a Real-Time Locational Adjusted Net Interchange Deviation at each Location equal to the difference in MWhs between (1) the Real-Time Locational Adjusted Net Interchange and (2) the Day-Ahead Locational Adjusted Net Interchange minus the Day-Ahead Demand Reduction Obligation for that Location.

(e) **Real-Time Energy Market Deviations For Demand Response Resources**

Real-Time Demand Reduction Obligation Deviation – Each Market Participant shall have for each settlement interval a Real-Time Demand Reduction Obligation Deviation at each Location equal to the difference in MWhs between the Real-Time Demand Reduction Obligation (calculated in accordance with Section III.3.2.1(c)) and the Day-Ahead Demand Reduction Obligation (calculated in accordance with Section III.3.2.1(a)(1)). For purposes of this calculation, if the Real-Time settlement interval is less than one hour, the Day-Ahead position shall be equally apportioned over the settlement intervals within the hour.

(f) **Day-Ahead Energy Market Energy Charge/Credit** – For each Market Participant for each settlement interval, the ISO will determine Day-Ahead Energy Market monetary positions representing a charge or credit for its net purchases from or sales to the ISO Day-Ahead Energy Market. The Day-Ahead Energy Market Energy Charge/Credit shall be equal to the sum of its Location specific Day-Ahead Locational Adjusted Net Interchanges multiplied by the Energy Component of the associated Day-Ahead Locational Marginal Prices. The Day-Ahead Energy Market Congestion Charge/Credit shall be equal to the sum of its Location specific Day-Ahead Locational Adjusted Net Interchanges multiplied by the Congestion Component of the associated Day-Ahead Locational Marginal Prices. The Day-Ahead Energy Market Loss Charge/Credit shall be equal to the sum of its Location specific Day-Ahead Locational Adjusted Net Interchanges multiplied by the Loss Component of the associated Day-Ahead Locational Marginal Prices.

(g) **Real-Time Energy Market Charge/Credit Excluding Demand Response Resources –** For each Market Participant for each settlement interval, the ISO will determine Real-Time Energy Market monetary positions representing a charge or credit to the Market Participant for its net purchases from or sales to the Real-Time Energy Market (excluding any such transactions involving Demand Response Resources). The Real-Time Energy Market Deviation Energy Charge/Credit shall be equal to the sum of the Market Participant's Location specific Real-Time Locational Adjusted Net Interchange Deviations for that settlement interval multiplied by the Energy Component of the Real-Time Locational Marginal Prices. The Real-Time Energy Market Deviation Congestion Charge/Credit shall be equal to the sum of the Market Participant's Location specific Real-Time Locational Adjusted Net Interchange Deviations for that settlement interval multiplied by the Congestion Component of the associated Real-Time Locational Marginal Prices. The Real-Time Energy Market Deviation Loss Charge/Credit shall be equal to the sum of the Market Participant's Location specific Real-Time Locational Adjusted Net Interchange Deviations for that settlement interval multiplied by the Loss Component of the associated Real-Time Locational Marginal Prices.

(h) **Real-Time Energy Market Charge/Credit For Demand Response Resources –** For each Market Participant for each settlement interval, the ISO shall calculate a charge or credit to the Market Participant for its net purchases from or sales to the Real-Time Energy Market associated with Demand Response Resources. The charge or credit shall be equal to the sum of the Market Participant's Location-specific Real-Time Demand Reduction Obligation Deviations for that settlement interval multiplied by the Real-Time Locational Marginal Prices. Such charges and credits shall be allocated on an hourly basis to Market Participants based on their pro rata share of the sum of all Market Participants' Real-Time Load Obligation, excluding the Real-Time Load Obligation incurred at all External Nodes, and excluding Real-Time Load Obligation incurred by Storage DARDs.

(i) **Day-Ahead and Real-Time Congestion Revenue** – For each settlement interval, the ISO will determine the total revenues associated with transmission congestion on the New England Transmission System. To accomplish this, the ISO will perform calculations to determine the following. The Day-Ahead Congestion Revenue shall equal the sum of all Market Participants' Day-Ahead Energy Market Congestion Charge/Credits. The Real-Time Congestion Revenue shall equal the sum of all Market Participants' Real-Time Energy Market Deviation Congestion Charge/Credits.

(j) **Day-Ahead Loss Revenue** – For each settlement interval, the ISO will determine the excess or deficiency in loss revenue associated with the Day-Ahead Energy Market. The Day-Ahead Loss Revenue shall be equal to the sum of all Market Participants' Day-Ahead Energy Market Energy Charge/Credits and Day-Ahead Energy Market Loss Charge/Credits.

(k) **Day-Ahead Loss Charges or Credits** – For each settlement interval for each Market Participant, the ISO shall calculate a Day-Ahead payment or charge associated with the excess or deficiency in loss revenue (Section III.3.2.1(j)). The Day-Ahead Loss Charges or Credits shall be equal to the Day-Ahead Loss Revenue multiplied by the Market Participant's pro rata share of the sum of all Market Participants' Marginal Loss Revenue Load Obligations.

(l) **Real-Time Loss Revenue** – For each settlement interval, the ISO will determine the excess or deficiency in loss revenue associated with the Real-Time Energy Market. The Real-Time Loss Revenue shall be equal to the sum of all Market Participants' Real-Time Energy Market Deviation Energy Charge/Credit and Real-Time Energy Market Deviation Loss Charge/Credit plus Non-Market Participant Transmission Customer loss costs. The ISO will then adjust Real-Time Loss Revenue to account for

Inadvertent Energy Revenue, as calculated under Section III.3.2.1(o) and Emergency transactions as described under Section III.4.3(a).

(m) **Real-Time Loss Revenue Charges or Credits** – For each hour for each Market Participant, the ISO shall calculate a Real-Time payment or charge associated with the excess or deficiency in Real-Time Loss Revenue (Section III.3.2.1(l)). The Real-Time Loss Revenue Charges or Credits shall be equal to the Real-Time Loss Revenue multiplied by the Market Participant's pro rata share of the sum of all Market Participants' Marginal Loss Revenue Load Obligations.

(n) **Non-Market Participant Loss** – Non-Market Participant Transmission Customer loss costs shall be assessed for transmission use scheduled in the Real-Time Energy Market, calculated as the amount to be delivered in each settlement interval multiplied by the difference between the Loss Component of the Real-Time Price at the delivery point or New England Control Area boundary delivery interface and the Loss Component of the Real-Time Price at the source point or New England Control Area boundary source interface.

(o) **Inadvertent Energy Revenue** – For each External Node, for each settlement interval the ISO will calculate an excess or deficiency in Inadvertent Energy Revenue by multiplying the Inadvertent Interchange at the External Node by the associated Real-Time Locational Marginal Price. For each settlement interval, the total Inadvertent Energy Revenue for a settlement interval shall equal the sum of the Inadvertent Energy Revenue values for each External Node for that interval.

(p) **Inadvertent Energy Revenue Charges or Credits** – For each hour for each Market Participant, the ISO shall calculate a Real-Time payment or charge associated with the excess or deficiency in Inadvertent Energy Revenue (Section III.3.2.1(o)). The Inadvertent Energy Revenue Charges or Credits shall be equal to the Inadvertent Energy Revenue multiplied by the Market Participant's pro rata share of the sum of all Market Participants' Real-Time Load Obligations, Real-Time Generation Obligations, and Real-Time Demand Reduction Obligations over all Locations, measured as absolute values, excluding contributions to Real-Time Load Obligations and Real-Time Generation Obligations from Coordinated External Transactions.

(q)(1) **Day-Ahead Energy Market Ancillary Services Credit** – Commencing on June 1, 2024, each Market Participant with a Day-Ahead Ancillary Services obligation shall receive a credit as follows:

(i) **Day-Ahead Ten-Minute Spinning Reserve credit** – Each MWh of Day-Ahead Ten-Minute Spinning Reserve Obligation shall be credited the clearing price for Day-Ahead Ten-Minute Spinning Reserve calculated in accordance with Section III.2.6.2(a)(v).

(ii) **Day-Ahead Ten-Minute Non-Spinning Reserve credit** – Each MWh of Day-Ahead Ten-Minute Non-Spinning Reserve Obligation shall be credited the clearing price for Day-Ahead Ten-Minute Non-Spinning Reserve calculated in accordance with Section III.2.6.2(a)(iv).

(iii) **Day-Ahead Thirty-Minute Operating Reserve credit** – Each MWh of Day-Ahead Thirty-Minute Operating Reserve Obligation shall be credited the clearing price for Day-Ahead Thirty-Minute Operating Reserve calculated in accordance with Section III.2.6.2(a)(iii).

(iv) **Day-Ahead Ninety-Minute Reserve credit** – Each MWh of Day-Ahead Ninety-Minute Reserve Obligation shall be credited the clearing price for Day-Ahead Ninety-Minute Reserve calculated in accordance with Section III.2.6.2(a)(ii).

(v) **Day-Ahead Four-Hour Reserve credit** – Each MWh of Day-Ahead Four-Hour Reserve Obligation shall be credited the clearing price for Day-Ahead Four-Hour Reserve calculated in accordance with Section III.2.6.2(a)(i).

(vi) **Day-Ahead Energy Imbalance Reserve credit** – Each MWh of Day-Ahead EnergImbalance Reserve Obligation shall be credited the clearing price for Day-Ahead Energy Imbalance Reserve calculated in accordance with Section III.2.6.2(a)(vi).

(q)(2) **Day-Ahead Energy Market Ancillary Services Close-Out Charge** – Commencing on June 1, 2024, each Market Participant with a Day-Ahead Ancillary Service obligation shall receive a charge as follows:

(i) **Day-Ahead Generation Contingency Reserve and Day-Ahead Replacement Energy Reserve –** Each MWh of Day-Ahead Ten-Minute Spinning Reserve Obligation, Day-Ahead Ten-Minute Non-Spinning Reserve Obligation, Day-Ahead Thirty-Minute Operating Reserve Obligation, Day-Ahead Ninety-Minute Reserve Obligation, and Day-Ahead Four-Hour Reserve Obligation shall be charged the close-out charge rate, which shall be the greater of (a) the hourly Real-Time Hub Price less the Energy Call Option Strike Price for the hour, and (b) zero.

(ii) **Day-Ahead Energy Imbalance Reserve –** Each MWh of Day-Ahead Energy Imbalance Reserve Obligation shall be charged the close out charge rate determined in accordance with subsection (q)(2)(i).

(q)(3) **Allocation of Net Day-Ahead Generation Contingency Reserve and Day-Ahead Replacement Energy Reserve Credits/Charges** – Commencing on June 1, 2024:

(i) The sum total credits calculated in accordance with Sections III.3.2.1(q)(1)(i)-(v) for Day-Ahead Generation Contingency Reserve and Day-Ahead Replacement Energy Reserve shall be charged on an hourly basis to Market Participants based on their pro rata share of the sum of all Market Participants' Real-Time Load Obligation, excluding Real-Time Load Obligation incurred by Storage DARDs;

(ii) The sum total close-out charges calculated in accordance with Section III.3.2.1(q)(2)(i) for Day-Ahead Generation Contingency Reserve and Day-Ahead Replacement Energy Reserve shall be credited on an hourly basis to Market Participants based on their pro rata share of the sum of all Market Participants' Real-Time Load Obligation, excluding Real-Time Load Obligation incurred by Storage DARDs.

(q)(4) **Allocation of Net Day-Ahead Energy Imbalance Reserve Credits/Charge** – Commencing on June 1, 2024:

(i) For purposes of this subsection (q)(4), the ISO will calculate a load deviation amount for each Market Participant. The load deviation shall be equal to the greater of (a) the MWh amount of the Market Participant's Real-Time Load Obligation (excluding Real-Time Load Obligation incurred by Storage DARDs) minus its Day-Ahead Load Obligation (excluding Day-Ahead Load Obligation incurred by Storage DARDs), or (b) zero.

(ii) The sum of credits calculated in accordance with Section III.3.2.1(q)(1)(vi) for Day-Ahead Energy Imbalance Reserve, if non-zero, shall be charged to Market Participants on an hourly basis as follows:

If the sum of (a) all Market Participants' load deviations and (b) accepted Increment Offers is

equal to or less than the total Day-Ahead Energy Imbalance Reserve Obligation amount, each Market Participant shall be charged: (1) the Day-Ahead Energy Imbalance Reserve clearing price, calculated in accordance with Section III.2.6.2(a)(vi) of this Market Rule 1, multiplied by the Market Participant's accepted Increment Offer amount, and (2) the Day-Ahead Energy Imbalance Reserve clearing price multiplied by the Market Participant's load deviation amount. The balance of any remaining credits for Day-Ahead Energy Imbalance Reserve Obligation shall be charged to Market Participants based on their pro rata share of the sum of all Market Participants' Real-Time Load Obligation, excluding Real-Time Load Obligation incurred by Storage DARDs.

If the sum of (a) all Market Participants' load deviations and (b) accepted Increment Offers is greater than the total Day-Ahead Energy Imbalance Reserve Obligation amount, and if the sum of all Market Participants' load deviations is greater than zero, each Market Participant shall be charged the Day-Ahead Energy Imbalance Reserve clearing price, calculated in accordance with Section III.2.6.2(a)(vi) of this Market Rule 1, multiplied by the Market Participant's accepted Increment Offer amount. The balance of any remaining credits for Day-Ahead Energy Imbalance Reserve Obligation shall be charged to Market Participants based on their pro rata share of the sum of all Market Participants' load deviations.

If the sum of all Market Participants' accepted Increment Offers is greater than the total Day-Ahead Energy Imbalance Reserve Obligation amount, and if the sum of all Market Participants' load deviations is zero, each MWh of a Market Participant's accepted Increment Offer shall be charged the Day-Ahead Energy Imbalance Reserve clearing price, calculated in accordance with Section III.2.6.2(a)(vi) of this Market Rule 1, multiplied by the total Day-Ahead Energy Imbalance Reserve Obligation amount and divided by the sum of all Market Participants' accepted Increment Offer amounts.

(iii) The sum of close-out charges calculated in accordance with Section III.3.2.1(q)(2)(ii) for Day-Ahead Energy Imbalance Reserve, if non-zero, shall be allocated to Market Participants on an hourly basis as follows:

If the sum of (a) all Market Participants' load deviations and (b) accepted Increment Offers is equal to or less than the total Day-Ahead Energy Imbalance Reserve Obligation amount, each Market Participant shall be credited an amount equal to: (1) close-out charge rate determined in

accordance with Section III.3.2.1(q)(2)(ii) for the settlement interval multiplied by the Market Participant's accepted Increment Offer amount, and (2) the close-out charge rate determined in accordance with Section III.3.2.1(q)(2)(ii) for the settlement interval, multiplied by their load deviation amount. The balance of any remaining charges for Day-Ahead Energy Imbalance Reserve Obligations shall be credited to Market Participants based on their pro rata share of the sum of all Market Participants' Real-Time Load Obligation, excluding Real-Time Load Obligation incurred by Storage DARDs.

If the sum of (a) all Market Participants' load deviations and (b) accepted Increment Offers is greater than the total Day-Ahead Energy Imbalance Reserve Obligation amount, and if the sum of all Market Participants' load deviations is greater than zero, each Market Participant shall be credited an amount equal to the close-out charge rate determined in accordance with Section III.3.2.1(q)(2)(ii) for the settlement interval multiplied by the Market Participant's accepted Increment Offer amount. The balance of any remaining charges for Day-Ahead Energy Imbalance Reserve Obligation shall be credited to Market Participants based on their pro rata share of the sum of all Market Participants' load deviations.

If the sum of all Market Participants' accepted increment Offers is greater than the total Day-Ahead Energy Imbalance Reserve Obligation amount, and if the sum of all Market Participants' load deviations is zero, each MWh of a Market Participant's accepted Increment Offer shall be credited an amount equal to the close-out charge rate determined in accordance with Section III.3.2.1(q)(2)(ii) for the settlement interval multiplied by the Market Participant's accepted Increment Offer amount, multiplied by the total Day-Ahead Energy Imbalance Reserve Obligation amount and divided by the sum of all Market Participants' accepted Increment Offer amounts.

(q)(5) **Forecast Energy Requirement Credit** - Commencing on June 1, 2024, Market Participants with Generator Assets, Demand Response Resources, and External Transactions for the supply of energy scheduled in the Day-Ahead Energy Market shall be credited the Forecast Energy Requirement Price, calculated in accordance with Section III.2.6.2(a)(vii), for each MWh of the resource's Day-Ahead energy obligation.

(q)(6) **Forecast Energy Requirement Charge** – The total amount credited in accordance with Section III.3.2.1(q)(5) shall be charged on an hourly basis to Market Participants as follows:

(i) Market Participants shall be charged the Forecast Energy Requirement Price, calculated in accordance with Section III.2.6.2(a)(vii), for each MWh of the Market Participant's Day-Ahead External Transaction sales.

(ii) The balance of any remaining credits shall be charged to Market Participants based on their pro rata share of the sum of all Market Participants' Real-Time Load Obligations, excluding Real-Time Load Obligations incurred by Real-Time External Transaction sales and Storage DARDs.

III.3.2.1.1 Metered Quantity For Settlement.

For purposes of determining the Metered Quantity For Settlement, the five-minute telemetry value for a five-minute interval is the integrated value of telemetered data sampled over the five-minute period. For settlement calculations that require hourly revenue quality meter value from Resources that submit five-minute revenue quality meter data, the hourly revenue quality meter value is the average of five-minute revenue quality meter values for the hour. The Metered Quantity For Settlement is calculated as follows:

(a) For external interfaces, the Metered Quantity For Settlement is the scheduled value adjusted for any curtailment, except that for Inadvertent Interchange, the Metered Quantity For Settlement is the difference between the actual and scheduled values, where the actual value is

(i) calculated as the five-minute telemetry value plus the difference between the hourly revenue quality meter value and the hourly average telemetry value, or

(ii) the five-minute revenue quality meter value, if five-minute revenue quality meter data are available.

(b) For Resources submitting five-minute revenue quality meter data (other than Demand Response Resources), the Metered Quantity For Settlement is the five-minute revenue quality meter value.

(c) For Resources with telemetry submitting hourly revenue quality meter data, the Metered Quantity For Settlement is calculated as follows:

(i) In the event that in an hour, the difference between the average of the five-minute telemetry values for the hour and the revenue quality meter value for the hour is greater than 20 percent of the hourly revenue quality meter value and greater than 10 MW then the Metered Quantity For Settlement is a flat profile of the revenue quality meter value equal to the hourly revenue quality meter value equally apportioned over the five-minute intervals in the hour. (For a Continuous Storage Facility, the difference between the

average of the five-minute telemetry values and the revenue quality meter value will be determined using the net of the values submitted by its component Generator Asset and DARD.)

(ii) Otherwise, the Metered Quantity For Settlement is the telemetry profile of the revenue quality meter value equal to the five-minute telemetry value adjusted by a scale factor.

(d) For a Demand Response Resource, the Metered Quantity For Settlement equals the sum of the demand reductions of each of its constituent Demand Response Assets produced in response to a non-zero Dispatch Instruction, with the demand reduction for each such asset calculated pursuant to Section III.8.4.

(e) For Resources without telemetry submitting hourly revenue quality meter data, the Metered Quantity For Settlement is the hourly revenue quality meter value equally apportioned over the five-minute intervals in the hour.

III.3.2.2 Metering and Communication.

(a) Revenue Quality Metering and Telemetry for Assets other than Demand Response Assets

The megawatt-hour data of each Generator Asset, Tie-Line Asset, and Load Asset must be metered and automatically recorded at no greater than an hourly interval using metering located at the asset's point of interconnection, in accordance with the ISO operating procedures on metering and telemetering. This metered value is used for purposes of establishing the hourly revenue quality metering of the asset.

The instantaneous megawatt data of each Generator Asset (except Settlement Only Resources) and each Asset Related Demand must be automatically recorded and telemetered in accordance with the requirements in the ISO operating procedures on metering and telemetering.

(b) Meter Maintenance and Testing for all Assets

Each Market Participant must adequately maintain metering, recording and telemetering equipment and must periodically test all such equipment in accordance with the ISO operating procedures on metering and telemetering. Equipment failures must be addressed in a timely manner in accordance with the requirements in the ISO operating procedures on maintaining communications and metering equipment.

(c) Additional Metering and Telemetry Requirements for Demand Response Assets

(i) Market Participants must report to the ISO in real time a set of telemetry data for each Demand Response Asset associated with a Demand Response Resource. The telemetry values shall measure the real-time demand of Demand Response Assets as measured at their Retail Delivery Points, and shall be reported to the ISO every five minutes. For a

Demand Response Resource to provide TMSR or TMNSR, Market Participants must in addition report telemetry values at least every one minute. Telemetry values reported by Market Participants to the ISO shall be in MW units and shall be an instantaneous power measurement or an average power value derived from an energy measurement for the time interval from which the energy measurement was taken.

(ii) If one or more generators whose output can be controlled is located behind the Retail Delivery Point of a Demand Response Asset, other than emergency generators that cannot operate electrically synchronized to the New England Transmission System, then the Market Participant must also report to the ISO, before the end of the Correction Limit for the Data Reconciliation Process, a single set of meter data, at an interval of five minutes, representing the combined output of all generators whose output can be controlled.

(iii) If the Market Participant or the ISO finds that the metering or telemetry devices do not meet the accuracy requirements specified in the ISO New England Manuals and Operating Procedures, the Market Participant shall promptly notify the ISO and indicate when it expects to resolve the accuracy problem(s), or shall request that the affected Demand Response Assets be retired. Once such an issue becomes known and until it is resolved, the demand reduction value and Operating Reserve capability of any affected Demand Response Asset shall be excluded from the Demand Response Resource with which it is associated.

(iv) The ISO may review and audit testing and calibration records, audit facility performance (including review of facility equipment), order and witness the testing of metering and telemetry measurement equipment, and witness the demand reduction activities of any facility or generator associated with a Demand Response Asset. Market Participants must make retail billing meter data and any interval meter data from the Host Participant for the facilities associated with a Demand Response Asset available to the ISO upon request.

(d) Overuse of Flat Profiling

In the event a Market Participant’s telemetry is replaced with an hourly flat profile pursuant to Section III.3.2.1.1(c)(i) more than 20% of the online hours in a month and Market Participant’s Resource has been online for over 50 hours in the month, the ISO may consult with the Market Participant for an explanation of the regular use of flat profiling and may request that the Market Participant address any telemetry discrepancies so that flat profiling is not regularly triggered.

Within 10 business days of issuance of such a request, the Market Participant shall provide the ISO with a written plan for remedying the deficiencies, and shall identify in the plan the specific actions to be taken and a reasonable timeline for completing such remediation. The Market Participant shall complete the remediation in accordance with and under the timeline set forth in the written plan.

III.3.2.3 NCPC Credits and Charges.

A Market Participant's NCPC Credits and NCPC Charges are calculated pursuant to Appendix F to Market Rule 1.

III.3.2.4 Transmission Congestion.

Market Participants shall be charged or credited for Congestion Costs as specified in Section III.3.2.1(i) of this Market Rule 1.

III.3.2.5 [Reserved.]

III.3.2.6 Emergency Energy.

(a) For each settlement interval during an hour in which there are Emergency Energy purchases, the ISO calculates an Emergency Energy purchase charge or credit equal to the Emergency Energy purchase price minus the External Node Real-Time LMP for the interval, multiplied by the Emergency Energy quantity for the interval. The charge or credit for each interval in an hour is summed to an hourly value. The ISO allocates the hourly charges or credits to Market Participants based on the following hourly deviations where such deviations are negative: (i) Real-Time Adjusted Load Obligation Deviations during that Operating Day; (ii) generation deviations and demand reduction deviations for those Pool-Scheduled Resources and Continuous Storage Generator Assets that are not following Dispatch Instructions; Self-Scheduled Resources (other than Continuous Storage Generator Assets) with dispatchable capability above their Self-Scheduled amounts not following Dispatch Instructions; and Self-Scheduled Resources (other than Continuous Storage Generator Assets) not following their Day-Ahead Self-Scheduled amounts other than those following Dispatch Instructions; in MWhs during the Operating Day; and (iii) deviations from the Day-Ahead Energy Market for External Transaction purchases in MWhs during the Operating Day except that positive Real-Time Generation Obligation Deviation at External Nodes associated with Emergency Energy purchases are not included in this calculation. Generator Assets and Demand Response Resources shall have a 5% or 5 MWh threshold when determining such deviations. Notwithstanding the foregoing, the allocation of costs or credits attributable to the purchase of Emergency

Energy from other Control Areas shall exclude contributions to deviations from Coordinated External Transactions.

(b) For each settlement interval during an hour in which there are Emergency Energy sales, the ISO calculates Emergency Energy sales revenue, exclusive of revenue from the Real-Time Energy Market, received from other Control Areas to provide the Emergency Energy sales. The revenues for each interval in an hour is summed to an hourly value. Hourly net revenues attributable to the sale of Emergency Energy to other Control Areas shall be credited to Market Participants based on the following deviations where such deviations are negative: (i) Real-Time Adjusted Load Obligation Deviations in MWhs during that Operating Day; (ii) generation deviations and demand reduction deviations for those Pool-Scheduled Resources and Continuous Storage Generator Assets that are following Dispatch Instructions; and Self-Scheduled Generator Assets (other than Continuous Storage Generator Assets) with dispatchable capability above their Self-Scheduled amounts following Dispatch Instructions; in MWhs during the Operating Day; and (iii) deviations from the Day-Ahead Energy Market for External Transaction purchases in MWhs during the Operating Day except that positive Real-Time Generation Obligation Deviation at External Nodes associated with Emergency Energy purchases are not included in this calculation. Generator Assets and Demand Response Resources shall have a 5% or 5 MWh threshold when determining such deviations. Notwithstanding the foregoing, the calculation of the credit for the sale of Emergency Energy to other Control Areas shall exclude contributions to deviations from Coordinated External Transactions.

III.3.2.6A New Brunswick Security Energy.

New Brunswick Security Energy is energy that is purchased from the New Brunswick System Operator by New England to preserve minimum flows on the Orrington-Keswick (396/3001) tie line and Orrington-Lepreau (390/3016) tie line in accordance with the applicable ISO / New Brunswick System Operator transmission operating guide with respect to the determination of minimum transfer limits. New Brunswick Security Energy costs are hourly costs in excess of the LMP at the applicable External Node attributable to purchases of New Brunswick Security Energy by New England. New Brunswick Security Energy costs shall be allocated among Market Participants on the basis of their pro-rata shares of Regional Network Load. Where the LMP at the applicable External Node exceeds the New Brunswick Security Energy costs, such amounts shall be accounted for in accordance with Section III.3.2.1(m).

III.3.2.7 Billing.

The ISO shall prepare a billing statement each billing cycle, in accordance with the ISO New England Billing Policy, for each Market Participant in accordance with the charges and credits specified in Sections III.3.2.1 through III.3.2.6, and showing the net amount to be paid or received by the Market Participant. Billing statements shall provide sufficient detail, as specified in the ISO New England Manuals, ISO New England Administrative Procedures and the ISO New England Billing Policy, to allow verification of the billing amounts and completion of the Market Participant's internal accounting. Billing disputes shall be settled in accordance with procedures specified in the ISO New England Billing Policy.

III.3.3 [Reserved.]

III.3.4 Non-Market Participant Transmission Customers.

III.3.4.1 Transmission Congestion.

Non-Market Participant Transmission Customers shall be charged or credited for Congestion Costs as specified in Section III.1 of this Market Rule 1.

III.3.4.2 Transmission Losses.

Non-Market Participant Transmission Customers shall be charged or credited for transmission losses in an amount equal to the product of (i) the Transmission Customer's MWhs of deliveries in the Real-Time Energy Market, multiplied by (ii) the difference between the Loss Components of the Real-Time Locational Marginal Prices at the point-of-receipt and the point-of-delivery Locations.

III.3.4.3 Billing.

The ISO shall prepare a billing statement each billing cycle, in accordance with the ISO New England Billing Policy, for each Non-Market Participant Transmission Customer in accordance with the charges and credits specified in Sections III.3.4.1 through III.3.4.2 of this Market Rule 1, and showing the net amount to be paid or received by the Non-Market Participant Transmission Customer. Billing statements shall provide sufficient detail, as specified in the ISO New England Manuals, the ISO New England Administrative Procedures and the ISO New England Billing Policy, to allow verification of the billing amounts and completion of the Non-Market Participant Transmission Customer's internal accounting. Billing disputes shall be settled in accordance with procedures specified in the ISO New England Billing Policy.

III.3.5 [Reserved.]

III.3.6 Data Reconciliation.

III.3.6.1 Data Correction Billing.

The ISO will reconcile Market Participant data errors and corrections after the Correction Limit for such data has passed. The Correction Limit for meter data and for ISO errors in the processing of meter and other Market Participant data is 101 days from the last Operating Day of the month to which the data applied. Notification of Meter Data Errors applicable to Assigned Meter Reader or Host Participant Assigned Meter Reader supplied meter data must be submitted to the ISO by the Meter Data Error RBA Submission Limit.

III.3.6.2 Eligible Data.

The ISO will accept revised hourly asset meter readings from Assigned Meter Readers and Host Participant Assigned Meter Readers, daily Coincident Peak Contribution values from Assigned Meter Readers, and new or revised internal bilateral transactions from Market Participants. No other revised data will be accepted for use in settlement recalculations. The ISO will correct data handling errors associated with other Market Participant supplied data to the extent that such data did not impact unit commitment or the Real-Time dispatch. Data handling errors that impacted unit commitment or the Real-Time dispatch will not be corrected.

III.3.6.3 Data Revisions.

The ISO will accept revisions to asset specific meter data, daily Coincident Peak Contribution values, and internal bilateral transactions prior to the Correction Limit. No revisions to other Market Participant data will be accepted after the deadlines specified in the ISO New England Manuals for submittal of that data have passed, except as provided in Section III.3.8 of Market Rule 1. If the ISO discovers a data error or if a Market Participant discovers and notifies the ISO of a data error prior to the Correction Limit, revised hourly data will be used to recalculate all markets and charges as appropriate, including but not limited to energy, NCPC, Regulation, Operating Reserves, Auction Revenue Rights allocations, Forward Capacity Market, cost-of-service agreements, and the ISO Tariff. No settlement recalculations or other adjustments may be made if the Correction Limit for the Operating Day to which the error applied has passed or if the correction does not qualify for treatment as a Meter Data Error correction pursuant to Section III.3.8 of Market Rule 1.

III.3.6.4 Meter Corrections Between Control Areas.

For revisions to meter data associated with assets that connect the New England Control Area to other Control Areas, the ISO will, in addition to performing settlement recalculations, adjust the actual interchange between the New England Control Area and the other Control Area to maintain an accurate record of inadvertent energy flow.

III.3.6.5 Meter Correction Data.

(a) Revised meter data and daily Coincident Peak Contribution values shall be submitted to the ISO as soon as it is available and not later than the Correction Limit, and must be submitted in accordance with the criteria specified in Section III.3.7 of Market Rule 1. Specific data submittal deadlines are detailed in the ISO New England Manuals.

(b) Errors on the part of the ISO in the administration of Market Participant supplied data shall be brought to the attention of the ISO as soon as possible and not later than the Correction Limit.

III.3.7 Eligibility for Billing Adjustments.

(a) Errors in Market Participant's statements resulting from errors in settlement software, errors in data entry by ISO personnel, and settlement production problems, that do not affect the day-ahead schedule or real-time system dispatch, will be corrected as promptly as practicable. If errors are identified prior to the issuance of final statements, the market will be resettled based on the corrected information.

(b) Calculations made by scheduling or dispatch software, operational decisions involving ISO discretion which affect scheduling or real-time operation, and the ISO's execution of mandatory dispatch directions, such as self-schedules or external contract conditions, are not subject to retroactive correction and resettlement. The ISO will settle and bill the Day-Ahead Energy Market as actually scheduled and the Real-Time Energy Market as actually dispatched. Any post-settlement issues raised concerning operating decisions related to these markets will be corrected through revision of operations procedures and guidelines on a prospective basis.

(c) While errors in reporting hourly metered data may be corrected (pursuant to Section III.3.8), Market Participants have the responsibility to ensure the correctness of all data they submit to the market settlement system.

(d) Disputes between Market Participants regarding settlement of internal bilateral transactions shall not be subject to adjustment by the ISO, but shall be resolved directly by the Market Participants unless they involve an error by the ISO that is subject to resolution under Section III.3.7(a).

(e) Billing disputes between Market Participants and the ISO or Non-Market Participants and the ISO shall be settled in accordance with procedures specified in the ISO New England Billing Policy.

(f) Criteria for Meter Data Errors to be eligible for a Requested Billing Adjustment. In order to be eligible to submit a Requested Billing Adjustment due to a Meter Data Error on an Invoice issued by the ISO after the completion of the Data Reconciliation Process, a Market Participant must satisfy one of the following two conditions: (1) the Meter Data Error at issue was identified by the asset owner, Assigned Meter Reader or the Host Participant Assigned Meter Reader and communicated to the Host Participant Assigned Meter Reader no later than thirty-six (36) days prior to the Correction Limit for Directly Metered Assets and no later than two (2) days prior to the Correction Limit for Profiled Load Assets and could not be resolved prior to those deadlines; or (2) the Meter Data Error at issue was identified by the asset owner, Assigned Meter Reader or Host Participant Assigned Meter Reader and reported to the ISO by the Meter Data Error RBA Submission Limit, and such Meter Data Error represents an error that is equal to or greater than the 1,000 MWh per Asset over a calendar month. If the Meter Data Error affects more than one metering domain, the ISO, and affected Host Participant Assigned Meter Readers and affected Assigned Meter Readers of affected metering domains, must be notified.

III.3.8 Correction of Meter Data Errors

(a) Any Market Participant, Assigned Meter Reader or Host Participant Assigned Meter Reader may submit notification of a Meter Data Error in accordance with the procedures provided in this Section III.3.8, provided that the notification is submitted no later than the Meter Data Error RBA Submission Limit and that the notice must be submitted using the RBA form for Meter Data Errors posted on the ISO's website. Errors in telemetry values used in calculating Metered Quantity For Settlement are not eligible for correction under this Section III.3.8.

(b) Within three Business Days of the receipt by the ISO's Chief Financial Officer of an RBA form for a Meter Data Error, the ISO shall prepare and submit to all Covered Entities and to the Chair of the NEPOOL Budget and Finance Subcommittee a notice of the Meter Data Error correction ("Notice of Meter Data Error Correction"), including, subject to the provisions of the ISO New England Information Policy, the specific details of the correction and the identity of the affected metering domains and the

affected Host Participant Assigned Meter Readers. The “Notice of Meter Data Error Correction” shall identify a specific representative of the ISO to whom all communications regarding the matter are to be sent.

(c) In order for a Meter Data Error on an Invoice issued by the ISO after the completion of the Data Reconciliation Process to be eligible for correction, the Meter Data Error must satisfy one of the following conditions: (1) the Meter Data Error at issue was identified by the asset owner, Assigned Meter Reader or the Host Participant Assigned Meter Reader and communicated to the Host Participant Assigned Meter Reader no later than 36 days prior to the Correction Limit for Directly Metered Assets and no later than two days prior to the Correction Limit for Profiled Load Assets and could not be resolved prior to those deadlines; (2) the Meter Data Error at issue was identified by the asset owner, Assigned Meter Reader or Host Participant Assigned Meter Reader, and such Meter Data Error represents an error that is equal to or greater than the 1,000 MWh per asset over a calendar month; and (3) if the Meter Data Error involves only Coincident Peak Contribution values, the average of the daily Meter Data Errors involving Coincident Peak Contribution values for the affected calendar month must be greater than or equal to 5 MW for an affected asset. If the Meter Data Error affects more than one metering domain, the ISO, and affected Host Participant Assigned Meter Readers and affected Assigned Meter Readers of affected metering domains, must be notified.

(d) For a Meter Data Error, the Host Participant Assigned Meter Reader must submit to the ISO corrected meter data for Directly Metered Assets prior to the 46th calendar day after the Meter Data Error RBA Submission Limit. Corrected metered data for Profiled Load Assets and Coincident Peak Contribution values, must be submitted to the ISO by the Host Participant Assigned Meter Reader prior to the 87th calendar day after the Meter Data Error RBA Submission Limit. Corrected internal bilateral transactions data must be submitted to the ISO by a Market Participant prior to the 91st calendar day after the Meter Data Error RBA Submission Limit.

Any corrected data received after the specified deadlines is not eligible for use in the settlement process.

The Host Participant Assigned Meter Reader or Market Participant, as applicable, must confirm as part of its submission of corrected data that the eligibility criteria described in Section III.3.8(c) of Market Rule 1 have been satisfied.

To the extent that the correction of a Meter Data Error is for a Directly Metered Asset that affects multiple metering domains, all affected Host Participant Assigned Meter Readers or Assigned Meter Readers must notify the ISO prior to the 46th calendar day after the Meter Data Error RBA Submission Limit that the corrected Directly Metered Asset data is acceptable to them in order for the ISO to use the corrected data in the final settlement calculations. The Host Participant Assigned Meter Reader for the Directly Metered Asset is responsible for initiating an e-mail to every affected Host Participant Assigned Meter Reader or Assigned Meter Reader in order to obtain such acceptance and shall coordinate delivery of such acceptance to the ISO. The Host Participant Assigned Meter Reader for the Directly Metered Asset is also responsible for submitting all corrected and agreed upon Directly Metered Asset data to the ISO prior to the 46th calendar day after the Meter Data Error RBA Submission Limit.

(e) After the submission of corrected meter and internal bilateral transactions data, the ISO will have a minimum of 30 calendar days to administer the final settlement based on that data. Revised data will be used to recalculate all charges and credits, except that revised data will not be used to recalculate the PER adjustment, including the Hourly PER and Monthly PER values. Revised data will also not be used to recalculate Demand Resource Seasonal Peak Hours. The results of the final settlement will then be included in the next Invoice containing Non-Hourly Charges and the ISO will provide to the Chair of the NEPOOL Budget and Finance Subcommittee written notification that the final settlement has been administered.

III.4 Rate Table

III.4.1 Offered Price Rates.

Day-Ahead energy, Day-Ahead Ancillary Services as of June 1, 2024, Real-Time energy, Regulation, Real-Time Operating Reserve, Forward Reserve, NCPC, Congestion Cost and transmission loss costs are based on offers and bids submitted to the ISO as specified in this Market Rule 1.

III.4.2 [Reserved.]

III.4.3 Emergency Energy Transaction.

The pricing for Emergency Energy and New Brunswick Security Energy purchases and sales will be determined in accordance with:

(a) an applicable agreement with an adjacent Control Area for Emergency and/or New Brunswick Security Energy purchases and sales, or

(b) arrangements made by the ISO with Market Participants, in accordance with procedures defined in the ISO New England Manuals, to purchase Emergency Energy offered by such Market Participant from External Transactions that are not associated with Import Capacity Resources. The ISO shall select offers to sell Emergency Energy made by Market Participants to the ISO on a least cost basis and the selected Market Participants shall receive payment for energy delivered at the higher of their offer price or the Real-Time Price at the applicable External Node. Such Emergency Energy purchases from Market Participants shall not be eligible to set Real-Time Prices.

III.13.2. Annual Forward Capacity Auction.

III.13.2.1. Timing of Annual Forward Capacity Auctions.

Each Forward Capacity Auction will be conducted beginning on the first Monday in the February that is approximately three years and four months before the beginning of the associated Capacity Commitment Period (unless, no later than the immediately preceding December 1, an alternative date is announced by the ISO), or, where exigent circumstances prevent the start of the Forward Capacity Auction at that time, as soon as possible thereafter.

III.13.2.2. Amount of Capacity Cleared in Each Forward Capacity Auction.

The total amount of capacity cleared in each Forward Capacity Auction shall be determined using the System-Wide Capacity Demand Curve and the Capacity Zone Demand Curves for the modeled Capacity Zones pursuant to Section III.13.2.3.3.

III.13.2.2.1. System-Wide Capacity Demand Curve.

The MRI Transition Period is the period from the Forward Capacity Auction for the Capacity Commitment Period beginning June 1, 2020 through the earlier of:

(i) the Forward Capacity Auction for which the amount of the Installed Capacity Requirement (net of HQICCs) that is filed by the ISO with the Commission pursuant to Section III.12.3 for the upcoming Forward Capacity Auction is greater than or equal to the sum of: 34,151 MW, and: (a) 722 MW (for the Forward Capacity Auction for the Capacity Commitment Period beginning June 1, 2020); (b) 375 MW (for the Forward Capacity Auction for the Capacity Commitment Period beginning June 1, 2021), or; (c) 150 MW (for the Forward Capacity Auction for the Capacity Commitment Period beginning June 1, 2022);

(ii) the Forward Capacity Auction for which the product of the system-wide Marginal Reliability Impact value, calculated pursuant to Section III.12.1.1, and the scaling factor specified in Section III.13.2.2.4, specifies a quantity at $7.03/kW-month in excess of the MW value determined under the applicable subsection (2)(b), (2)(c), or (2)(d), below, or;

(iii) the Forward Capacity Auction for the Capacity Commitment Period beginning June 1, 2022.

During the MRI Transition Period, the System-Wide Capacity Demand Curve shall consist of the following three segments:

(1) at prices above \$7.03/kW-month and below the Forward Capacity Auction Starting Price, the System-Wide Capacity Demand Curve shall specify a price for system capacity quantities based on the product of the system-wide Marginal Reliability Impact value, calculated pursuant to Section III.12.1.1, and the scaling factor specified in Section III.13.2.2.4;

(2) at prices below \$7.03/kW-month, the System-Wide Capacity Demand Curve shall be linear between \$7.03/kW-month and \$0.00/kW-month and determined by the following quantities:

(a) At the price of \$0.00/kW-month, the quantity specified by the System-Wide Capacity Demand Curve shall be 1616 MW plus the MW value determined under the applicable provision in (b), (c), or (d) of this subsection.

(b) for the Forward Capacity Auction for the Capacity Commitment Period beginning June 1, 2020, at \$7.03/kW-month, the quantity shall be the lesser of:

1. 35,437 MW; and
2. 722 MW plus the quantity at which the product of the system-wide Marginal Reliability Impact value and the scaling factor yield a price of \$7.03/kW-month;

(c) for the Forward Capacity Auction for the Capacity Commitment Period beginning June 1, 2021, at \$7.03/kW-month, the quantity shall be the lesser of:

1. 35,090 MW; and
2. 375 MW plus the quantity at which the product of the system-wide Marginal Reliability Impact value and the scaling factor yield a price of \$7.03/kW-month;

(d) for the Forward Capacity Auction for the Capacity Commitment Period beginning June 1, 2022, at \$7.03/kW-month, the quantity shall be the lesser of:

1. 34,865 MW; and
2. 150 MW plus the quantity at which the product of the system-wide Marginal Reliability Impact value and the scaling factor yield a price of \$7.03/kW-month

(3) a price of $7.03/kW-month for all quantities between those curves segments.

In addition to the foregoing, the System-Wide Capacity Demand Curve shall not specify a price in excess of the Forward Capacity Auction Starting Price.

Following the MRI Transition Period, the System-Wide Capacity Demand Curve shall specify a price for system capacity quantities based on the product of the system-wide Marginal Reliability Impact value, calculated pursuant to Section III.12.1.1, and the scaling factor specified in Section III.13.2.2.4. For any system capacity quantity greater than 110% of the Installed Capacity Requirement (net of HQICCs), the System-Wide Capacity Demand Curve shall specify a price of zero. The System-Wide Capacity Demand Curve shall not specify a price in excess of the Forward Capacity Auction Starting Price.

III.13.2.2.2. Import-Constrained Capacity Zone Demand Curves.

For each import-constrained Capacity Zone, the Capacity Zone Demand Curve shall specify a price for all Capacity Zone quantities based on the product of the import-constrained Capacity Zone's Marginal Reliability Impact value, calculated pursuant to Section III.12.2.1.3, and the scaling factor specified in Section III.13.2.2.4. The prices specified by an import-constrained Capacity Zone Demand Curve shall be non-negative. At all quantities greater than the truncation point, which is the amount of capacity for which the Capacity Zone Demand Curve specifies a price of $0.01/kW-month, the Capacity Zone Demand Curve shall specify a price of zero. The Capacity Zone Demand Curve shall not specify a price in excess of the Forward Capacity Auction Starting Price.

III.13.2.2.3. Export-Constrained Capacity Zone Demand Curves.

For each export-constrained Capacity Zone, the Capacity Zone Demand Curve shall specify a price for all Capacity Zone quantities based on the product of the export-constrained Capacity Zone's Marginal Reliability Impact value, calculated pursuant to Section III.12.2.2.1, and the scaling factor specified in Section III.13.2.2.4. The prices specified by an export-constrained Capacity Zone Demand Curve shall be non-positive. At all quantities less than the truncation point, which is the amount of capacity for which the Capacity Zone Demand Curve specifies a price of negative $0.01/kW-month, the Capacity Zone Demand Curve shall specify a price of zero.

III.13.2.2.4. Capacity Demand Curve Scaling Factor.

The demand curve scaling factor shall be set at the value such that, at the quantity specified by the System-Wide Capacity Demand Curve at a price of Net CONE, the Loss of Load Expectation is 0.1 days per year.

III.13.2.3. Conduct of the Forward Capacity Auction.

The Forward Capacity Auction shall include a descending clock auction, which will determine, subject to the provisions of Section III.13.2.7, the Capacity Clearing Price for each Capacity Zone modeled in that Forward Capacity Auction pursuant to Section III.12.4, and the Capacity Clearing Price for certain offers from New Import Capacity Resources and Existing Import Capacity Resources pursuant to Section III.13.2.3.3(d). The Forward Capacity Auction shall determine the outcome of all offers and bids accepted during the qualification process and submitted during the auction. The descending clock auction shall be conducted as a series of rounds, which shall continue (for up to five consecutive Business Days, with up to eight rounds per day, absent extraordinary circumstances) until the Forward Capacity Auction is concluded for all modeled Capacity Zones in accordance with the provisions of Section III.13.2.3.3. Each round of the Forward Capacity Auction shall consist of the following steps, which shall be completed simultaneously for each Capacity Zone included in the round:

III.13.2.3.1. Step 1: Announcement of Start-of-Round Price and End-of-Round Price.

For each round, the auctioneer shall announce a single Start-of-Round Price (the highest price associated with a round of the Forward Capacity Auction) and a single (lower) End-of-Round Price (the lowest price associated with a round of the Forward Capacity Auction). In the first round, the Start-of-Round Price shall equal the Forward Capacity Auction Starting Price for all modeled Capacity Zones. In each round after the first round, the Start-of-Round Price shall equal the End-of-Round Price from the previous round.

III.13.2.3.2. Step 2: Compilation of Offers and Bids.

The auctioneer shall compile all of the offers and bids for that round, as follows:

(a) **Offers from New Generating Capacity Resources, New Import Capacity Resources, and New Demand Capacity Resources.**

(i) The Project Sponsor for any New Generating Capacity Resource, New Import Capacity Resource that is backed by a single new External Resource and that is associated with an investment in transmission that increases New England’s import capability, New Import Capacity

Resource that is associated with an Elective Transmission Upgrade, or New Demand Capacity Resource accepted in the qualification process for participation in the Forward Capacity Auction may submit a New Capacity Offer indicating the quantity of capacity that the Project Sponsor would commit to provide from the resource during the Capacity Commitment Period at that round's prices. A New Capacity Offer shall be defined by the submission of one to five prices, each strictly less than the Start-of-Round Price but greater than or equal to the End-of-Round Price, and an associated quantity in the applicable Capacity Zone. Each price shall be expressed in units of dollars per kilowatt-month to an accuracy of at most three digits to the right of the decimal point, and each quantity shall be expressed in units of MWs to an accuracy of at most three digits to the right of the decimal point. A New Capacity Offer shall imply a supply curve indicating quantities offered at all of that round's prices, pursuant to the convention of Section III.13.2.3.2(a)(iii).

(ii) If the Project Sponsor of a New Generating Capacity Resource, New Import Capacity Resource that is backed by a single new External Resource and that is associated with an investment in transmission that increases New England's import capability, New Import Capacity Resource that is associated with an Elective Transmission Upgrade, or New Demand Capacity Resource elects to offer in a Forward Capacity Auction, the Project Sponsor must offer the resource's full FCA Qualified Capacity at the Forward Capacity Auction Starting Price in the first round of the auction. A New Capacity Offer for a resource may in no event be for greater capacity than the resource's full FCA Qualified Capacity at any price. A New Capacity Offer for a resource may not be for less capacity than the resource's Rationing Minimum Limit at any price, except where the New Capacity Offer is for a capacity quantity of zero.

(iii) Let the Start-of-Round Price and End-of-Round Price for a given round be P_S and P_E, respectively. Let the m prices ($1 \leq m \leq 5$) submitted by a Project Sponsor for a modeled Capacity Zone be $p_1, p_2, \ldots, p_m$, where $P_S > p_1 > p_2 > \ldots > p_m \geq P_E$, and let the associated quantities submitted for a New Capacity Resource be $q_1, q_2, \ldots, q_m$. Then the Project Sponsor's supply curve, for all prices strictly less than P_S but greater than or equal to P_E, shall be taken to be:

$$S(p)=\begin{cases} q_0, & \text{if } p > p_1, \\ q_1, & \text{if } p_2 < p \le p_1, \\ q_2, & \text{if } p_3 < p \le p_2, \\ \cdots & \cdots \quad , \\ q_m, & \text{if } p \le p_m. \end{cases}$$

where, in the first round, q_0 is the resource's full FCA Qualified Capacity and, in subsequent rounds, q_0 is the resource's quantity offered at the lowest price of the previous round.

(iv) Except for Renewable Technology Resources and except as provided in Section III.13.2.3.2(a)(v), a New Capacity Resource may not include any capacity in a New Capacity Offer during the Forward Capacity Auction at any price below the resource's New Resource Offer Floor Price. The amount of capacity included in each New Capacity Offer at each price shall be included in the aggregate supply curves at that price as described in Section III.13.2.3.3.

(v) Capacity associated with a New Import Capacity Resource (other than a New Import Capacity Resource that is backed by a single new External Resource and that is associated with an investment in transmission that increases New England's import capability or a New Import Capacity Resource that is associated with an Elective Transmission Upgrade) shall be automatically included in the aggregate supply curves as described in Section III.13.2.3.3 at prices at or above the resource's offer prices (as they may be modified pursuant to Section III.A.21.2) and shall be automatically removed from the aggregate supply curves at prices below the resource's offer prices (as they may be modified pursuant to Section III.A.21.2), except under the following circumstances:

In any round of the Forward Capacity Auction in which prices are below the Dynamic De-List Bid Threshold, the Project Sponsor for a New Import Capacity Resource (other than a New Import Capacity Resource that is backed by a single new External Resource and that is associated with an investment in transmission that increases New England's import capability or a New Import Capacity Resource that is associated with an Elective Transmission Upgrade) with offer prices (as they may be modified pursuant to Section III.A.21.2) that are less than the Dynamic Delist Bid Threshold may submit a New Capacity Offer indicating the quantity of capacity that the Project Sponsor would commit to provide from the resource during the Capacity Commitment Period at that round's prices. Such an offer shall be defined by the submission of one to five

prices, each less than the Dynamic De-List Bid Threshold (or the Start-of-Round Price, if lower than the Dynamic De-List Bid Threshold) but greater than or equal to the End-of-Round Price, and a single quantity associated with each price. Such an offer shall be expressed in the same form as specified in Section III.13.2.3.2(a)(i) and shall imply a curve indicating quantities at all of that round's relevant prices, pursuant to the convention of Section III.13.2.3.2(a)(iii). The curve may not increase the quantity offered as the price decreases.

(b) **Bids from Existing Capacity Resources**

(i) Static De-List Bids, Permanent De-List Bids, Retirement De-List Bids, and Export Bids from Existing Generating Capacity Resources, Existing Import Capacity Resources, and Existing Demand Capacity Resources, as finalized in the qualification process or as otherwise directed by the Commission shall be automatically bid into the appropriate rounds of the Forward Capacity Auction, such that each such resource's FCA Qualified Capacity will be included in the aggregate supply curves as described in Section III.13.2.3.3 until any Static De-List Bid, Permanent De-List Bid, Retirement D-List Bid, or Export Bid clears in the Forward Capacity Auction, as described in Section III.13.2.5.2, and is removed from the aggregate supply curves. In the case of a Commission-approved Permanent De-List Bid or Commission-approved Retirement De-List Bid at or above the Forward Capacity Auction Starting Price, or where a Permanent De-List Bid or Retirement De-List Bid is subject to an election under Section III.13.1.2.4.1(a), the resource's FCA Qualified Capacity will be reduced by the quantity of the de-list bid (unless the resource was retained for reliability pursuant to Section III.13.1.2.3.1.5.1) and the Permanent De-List Bid or Retirement De-List Bid shall not be included in the Forward Capacity Auction. Permanent De-List Bids and Retirement De-List Bids subject to an election under Section III.13.1.2.4.1(a) or Section III.13.1.2.4.1(b) shall not be included in the Forward Capacity Auction and shall be treated according to Section III.13.2.3.2(b)(ii). In the case of a Static De-List Bid, if the Market Participant revised the bid pursuant to Section III.13.1.2.3.1.1, then the revised bid shall be used in place of the submitted bid; if the Market Participant withdrew the bid pursuant to Section III.13.1.2.3.1.1, then the capacity associated with the withdrawn bid shall be entered into the auction pursuant to Section III.13.2.3.2(c). If the amount of capacity associated with Export Bids for an interface exceeds the transfer limit of that interface (minus any accepted Administrative De-List Bids over that interface), then the set of Export Bids associated with that interface equal to the interface's transfer limit (minus any accepted Administrative De-List Bids over that interface) having the highest bid prices shall be included in the auction as described above;

capacity for which Export Bids are not included in the auction as a result of this provision shall be entered into the auction pursuant to Section III.13.2.3.2(c).

(ii) For Permanent De-List Bids and Retirement De-List Bids, the ISO will enter a Proxy De-List Bid into the appropriate rounds of the Forward Capacity Auction in the following circumstances: (1) if the Lead Market Participant has elected pursuant to Section III.13.1.2.4.1(a) to retire the resource or portion thereof, the resource has not been retained for reliability pursuant to Section III.13.1.2.3.1.5.1, the price specified in the Commission-approved de-list bid is less than the Forward Capacity Auction Starting Price, and the Internal Market Monitor has found a portfolio benefit pursuant to Section III.A.24; or (2) if the Lead Market Participant has elected conditional treatment pursuant to Section III.13.1.2.4.1(b), the resource has not been retained for reliability pursuant to Section III.13.1.2.3.1.5.1, and the price specified in the Commission-approved de-list bid is less than the price specified in the de-list bid submitted by the Lead Market Participant and less than the Forward Capacity Auction Starting Price. The Proxy De-List Bid shall be non-rationable and shall be equal in price and quantity to, and located in the same Capacity Zone as, the Commission-approved Permanent De-List Bid or Commission-approved Retirement De-List Bid, and shall be entered into the appropriate rounds of the Forward Capacity Auction such that the capacity associated with the Proxy De-List Bid will be included in the aggregate supply curves as described in Section III.13.2.3.3 until the Proxy De-List Bid clears in the Forward Capacity Auction, as described in Section III.13.2.5.2, and is removed from the aggregate supply curves. If the Lead Market Participant has elected conditional treatment pursuant to Section III.13.1.2.4.1(b), the resource has not been retained for reliability pursuant to Section III.13.1.2.3.1.5.1, and the Commission-approved Permanent De-List Bid or Commission-approved Retirement De-List Bid is equal to or greater than the de-list bid submitted by the Lead Market Participant, no Proxy De-List Bid shall be used and the Commission-approved de-list bid shall be entered in the Forward Capacity Auction pursuant to Section III.13.2.3.2(b)(i).

(iii) For purposes of this subsection (b), if an Internal Market Monitor-determined price has been established for a Static De-List Bid and the associated resource's capacity is pivotal pursuant to Sections III.A.23.1 and III.A.23.2, then (unless otherwise directed by the Commission) the lower of the Internal Market Monitor-determined price and any revised bid that is submitted pursuant to Section III.13.1.2.3.1.1 will be used in place of the initially submitted bid; provided, however, that if the bid was withdrawn pursuant to Section III.13.1.2.3.1.1, then the capacity associated with the withdrawn bid shall be entered into the auction pursuant to

Section III.13.2.3.2(c). If an Internal Market Monitor-determined price has been established for an Export Bid and the associated resource's capacity is pivotal pursuant to Sections III.A.23.1 and III.A.23.2, then the Internal Market Monitor-determined price (or price directed by the Commission) will be used in place of the submitted bid.

Any Static De-List Bid for ambient air conditions that has not been verified pursuant to Section III.13.1.2.3.2.4 shall not be subject to the provisions of this subsection (b).

(c) **Existing Capacity Resources Without De-List or Export Bids and Self-Supplied FCA Resources**. Each Existing Generating Capacity Resource, Existing Import Capacity Resource, and Existing Demand Capacity Resource without a Static De-List Bid, a Permanent De-List Bid, a Retirement De-List Bid, an Export Bid or an Administrative Export De-List Bid in its Existing Capacity Qualification Package, and each existing Self-Supplied FCA Resource shall be automatically entered into each round of the Forward Capacity Auction at its FCA Qualified Capacity, such that the resource's FCA Qualified Capacity will be included in the aggregate supply curves as described in Section III.13.2.3.3, except where such resource, if permitted, submits an appropriate Dynamic De-List Bid, as described in Section III.13.2.3.2(d). Each new Self-Supplied FCA Resource shall be automatically entered into each round of the Forward Capacity Auction at its designated self-supplied quantity at prices at or above the resource's New Resource Offer Floor Price, such that the resource's designated self-supply quantity will be included in the aggregate supply curves as described in Section III.13.2.3.3.

(d) **Dynamic De-List Bids.** In any round of the Forward Capacity Auction in which prices are below the Dynamic De-List Bid Threshold, any Existing Generating Capacity Resource, Existing Import Capacity Resource, or Existing Demand Capacity Resource (but not any Self-Supplied FCA Resources) may submit a Dynamic De-List Bid at prices below the Dynamic De-List Bid Threshold. Such a bid shall be defined by the submission of one to five prices, each less than the Dynamic De-List Bid Threshold (or the Start-of-Round Price, if lower than the Dynamic De-List Bid Threshold) but greater than or equal to the End-of-Round Price, and a single quantity associated with each price. Such a bid shall be expressed in the same form as specified in Section III.13.2.3.2(a)(i) and shall imply a curve indicating quantities at all of that round's relevant prices, pursuant to the convention of Section III.13.2.3.2(a)(iii). The curve may in no case increase the quantity offered as the price decreases. A dynamic De-List Bid may not offer less capacity than the resource's Rationing Minimum Limit at any price, except where the amount of capacity offered is zero. All Dynamic De-List Bids are subject to a reliability review as described in Section III.13.2.5.2.5, and if not rejected for reliability reasons, shall be included in the round in the same

manner as Static De-List Bids as described in Section III.13.2.3.2(b). Where a resource elected pursuant to Section III.13.1.1.2.2.4 or Section III.13.1.4.1.1.2.7 to have the Capacity Supply Obligation and Capacity Clearing Price continue to apply after the Capacity Commitment Period associated with the Forward Capacity Auction in which the offer clears, the capacity associated with any resulting Capacity Supply Obligation may not be subject to a Dynamic De-List Bid in subsequent Forward Capacity Auctions for Capacity Commitment Periods for which the Project Sponsor elected to have the Capacity Supply Obligation and Capacity Clearing Price continue to apply. Where a Lead Market Participant submits any combination of Dynamic De-List Bid, Static De-List Bid, Export Bid, and Administrative Export De-List Bid for a single resource, none of the prices in a set of price-quantity pairs associated with a bid may be the same as any price in any other set of price-quantity pairs associated with another bid for the same resource.

(e) **Repowering**. Offers and bids associated with a resource participating in the Forward Capacity Auction as a New Generating Capacity Resource pursuant to Section III.13.1.1.1.2 (resources previously counted as capacity resources) shall be addressed in the Forward Capacity Auction in accordance with the provisions of this Section III.13.2.3.2(e). The Project Sponsor shall offer such a New Generating Capacity Resource into the Forward Capacity Auction in the same manner and pursuant to the same rules as other New Generating Capacity Resources, as described in Section III.13.2.3.2(a). As long as any capacity is offered from the New Generating Capacity Resource, the amount of capacity offered is the amount that the auctioneer shall include in the aggregate supply curve at the relevant prices, and the quantity of capacity offered from the associated Existing Generating Capacity Resource shall not be included in the aggregate supply curve. If any portion of the New Generating Capacity Resource clears in the Forward Capacity Auction, the associated Existing Generating Capacity Resource shall be permanently de-listed as of the start of the associated Capacity Commitment Period. If at any price, no capacity is offered from the New Generating Capacity Resource, then the auctioneer shall include capacity from the associated Existing Generating Capacity Resource at that price, subject to any bids submitted and accepted in the qualification process for that Existing Generating Capacity Resource pursuant to Section III.13.1.2.5. Bids submitted and accepted in the qualification process for an Existing Generating Capacity Resource pursuant to Section III.13.1.2.5 shall only be entered into the Forward Capacity Auction after the associated New Generating Capacity Resource is fully withdrawn (that is, the Forward Capacity Auction reaches a price at which the resource’s New Capacity Offer is zero capacity), and shall only then be subject to the reliability review described in Section III.13.2.5.2.5.

(f) **Conditional Qualified New Resources.** Offers associated with a resource participating in the Forward Capacity Auction as a Conditional Qualified New Resource pursuant to Section III.13.1.1.2.3(f) shall be addressed in the Forward Capacity Auction in accordance with the provisions of this Section III.13.2.3.2(f). The Project Sponsor shall offer such a Conditional Qualified New Resource into the Forward Capacity Auction in the same manner and pursuant to the same rules as other New Generating Capacity Resources, as described in Section III.13.2.3.2(a). An offer from at most one resource at a Conditional Qualified New Resource's location will be permitted to clear (receive a Capacity Supply Obligation for the associated Capacity Commitment Period) in the Forward Capacity Auction. As long as a positive quantity is offered at the End-of-Round Price in the final round of the Forward Capacity Auction by the resource having a higher queue priority at the Conditional Qualified New Resource's location, as described in Section III.13.1.1.2.3(f), then no capacity from the Conditional Qualified New Resource shall clear. If at any price greater than or equal to the End-of-Round Price in the final round of the Forward Capacity Auction, zero quantity is offered from the resource having higher queue priority at the Conditional Qualified New Resource's location, as described in Section III.13.1.1.2.3(f), then the auctioneer shall consider capacity offered from the Conditional Qualified New Resource in the determination of clearing, including the application of Section III.13.2.7.

(g) **Mechanics**. Offers and bids that may be submitted during a round of the Forward Capacity Auction must be received between the starting time and ending time of the round, as announced by the auctioneer in advance. The ISO at its sole discretion may authorize a participant in the auction to complete or correct its submission after the ending time of a round, but only if the participant can demonstrate to the ISO's satisfaction that the participant was making reasonable efforts to complete a valid offer submission before the ending time of the round, and only if the ISO determines that allowing the completion or correction will not unreasonably disrupt the auction process. All decisions by the ISO concerning whether or not a participant may complete or correct a submission after the ending time of a round are final.

III.13.2.3.3. Step 3: Determination of the Outcome of Each Round.

The auctioneer shall use the offers and bids for the round as described in Section III.13.2.3.2 to determine the aggregate supply curves for the New England Control Area and for each modeled Capacity Zone included in the round.

The aggregate supply curve for the New England Control Area, the Total System Capacity, shall reflect at each price the sum of the following:

(1) the amount of capacity offered in all Capacity Zones modeled as import-constrained Capacity Zones at that price (excluding capacity offered from New Import Capacity Resources and Existing Import Capacity Resources);

(2) the amount of capacity offered in the Rest-of-Pool Capacity Zone at that price (excluding capacity offered from New Import Capacity Resources and Existing Import Capacity Resources);

(3) for each Capacity Zone modeled as an export-constrained Capacity Zone, the lesser of:

    (i) the amount of capacity offered in the Capacity Zone at that price (including the amount of capacity offered from New Import Capacity Resources and Existing Import Capacity Resources for each interface between the New England Control Area and an external Control Area mapped to the export-constrained Capacity Zone up to that interface's approved capacity transfer limit (net of tie benefits)), or;

    (ii) the amount of capacity determined by the Capacity Zone Demand Curve at zero minus that price, and;

(4) for each interface between the New England Control Area and an external Control Area mapped to an import-constrained Capacity Zone or the Rest-of-Pool Capacity Zone, the lesser of:

    (i) that interface's approved capacity transfer limit (net of tie benefits), or;

    (ii) the amount of capacity offered from New Import Capacity Resources and Existing Import Capacity Resources.

In computing the Total System Capacity, capacity associated with any New Capacity Offer at any price greater than the Forward Capacity Auction Starting Price will not be included in the tally of total capacity at the Forward Capacity Auction Starting Price for that Capacity Zone. On the basis of these aggregate supply curves, the auctioneer shall determine the outcome of the round for each modeled Capacity Zone as follows:

(a) **Import-Constrained Capacity Zones.**

For a Capacity Zone modeled as an import-constrained Capacity Zone, if either of the following two conditions is met during the round:

(1) the aggregate supply curve for the import-constrained Capacity Zone, adjusted as necessary in accordance with Section III.13.2.6 (Capacity Rationing Rule), equals or is less than the quantity determined by the Capacity Zone Demand Curve at the difference between the End-of-Round Price and the price specified by the System-Wide Capacity Demand Curve (at a quantity no less than Total System Capacity at the Start-of-Round Price), or;

(2) the Forward Capacity Auction is concluded for the Rest-of-Pool Capacity Zone;

then the Forward Capacity Auction for that Capacity Zone is concluded and such Capacity Zone will not be included in further rounds of the Forward Capacity Auction.

The Capacity Clearing Price for that Capacity Zone shall be set at the greater of: (1) the sum of the price specified by the Capacity Zone Demand Curve at the amount of capacity equal to the total amount that is awarded a Capacity Supply Obligation in the import-constrained Capacity Zone, and the Capacity Clearing Price for the Rest-of-Pool Capacity Zone, or; (2) the highest price of any offer or bid for a resource in the Capacity Zone that is awarded a Capacity Supply Obligation, subject to the other provisions of this Section III.13.2.

If neither of the two conditions above are met in the round, then that Capacity Zone will be included in the next round of the Forward Capacity Auction.

(b) **Rest-of-Pool Capacity Zone**.

If the Total System Capacity at the End-of-Round Price, adjusted as necessary in accordance with Section III.13.2.6 (Capacity Rationing Rule), and adjusted to include the additional supply in the import-constrained Capacity Zone that may be cleared at a higher price, equals or is less than the amount of capacity determined by the System-Wide Capacity Demand Curve, then the Forward Capacity Auction for the Rest-of-Pool Capacity Zone is concluded and the Rest-of-Pool Capacity Zone will not be included in further rounds of the Forward Capacity Auction.

The Capacity Clearing Price for the Rest-of-Pool Capacity Zone shall be set at the highest price at which the Total System Capacity is less than or equal to the amount of capacity determined by the System-Wide Capacity Demand Curve, subject to the other provisions of this Section III.13.2.

If the Forward Capacity Auction for the Rest-of-Pool Capacity Zone is not concluded then the Rest-of-Pool Capacity Zone will be included in the next round of the Forward Capacity Auction, and the auctioneer shall publish the Total System Capacity at the End-of-Round Price, adjusted to include the additional supply in the import-constrained Capacity Zone that may be cleared at a higher price, less the amount of capacity determined by the System-Wide Capacity Demand Curve at the End-of-Round Price.

(c) **Export-Constrained Capacity Zones**.

For a Capacity Zone modeled as an export-constrained Capacity Zone, if all of the following conditions are met during the round:

(1) the aggregate supply curve for the export-constrained Capacity Zone, adjusted as necessary in accordance with Section III.13.2.6 (Capacity Rationing Rule), is equal to or less than the maximum amount of capacity determined by the Capacity Zone Demand Curve at a price of zero;

(2) in the case of a nested Capacity Zone, the Forward Capacity Auction is concluded for the Capacity Zone within which the nested Capacity Zone is located, and;

(3) the Forward Capacity Auction is concluded for the Rest-of-Pool Capacity Zone;

then the Forward Capacity Auction for that Capacity Zone is concluded and such Capacity Zone will not be included in further rounds of the Forward Capacity Auction.

The Capacity Clearing Price for an export-constrained Capacity Zone that is not a nested export-constrained Capacity Zone shall be set at the greater of:

(1) the sum of:

(i) the price specified by the Capacity Zone Demand Curve at the amount of capacity equal to the total amount that is awarded a Capacity Supply Obligation in that Capacity Zone; and

(ii) the Capacity Clearing Price for the Rest-of-Pool Capacity Zone.

or;

(2) the highest price of any offer or bid for a resource in the Capacity Zone that is awarded a Capacity Supply Obligation, and subject to the other provisions of this Section III.13.2.

The Capacity Clearing Price for a nested export-constrained Capacity Zone shall be set at the greater of:

(1) the sum of:

(i) the price specified by the Capacity Zone Demand Curve at the amount of capacity equal to the total amount that is awarded a Capacity Supply Obligation in that Capacity Zone; and

(ii) the Capacity Clearing Price for the Capacity Zone in which the nested Capacity Zone is located,

or;

(2) the highest price of any offer or bid for a resource in the Capacity Zone that is awarded a Capacity Supply Obligation, subject to the other provisions of this Section III.13.2.

If all of the conditions above are not satisfied in the round, then the auctioneer shall publish the quantity of excess supply in the export-constrained Capacity Zone at the End-of-Round Price (the amount of capacity offered at the End-of-Round Price in the export-constrained Capacity Zone minus the maximum amount of capacity determined by the Capacity Zone Demand Curve at a price of zero) and that Capacity Zone will be included in the next round of the Forward Capacity Auction.

(d) **Treatment of Import Capacity.** Where the amount of capacity offered from New Import Capacity Resources and Existing Import Capacity Resources over an interface between the New England Control Area and an external Control Area is less than or equal to that interface's approved capacity transfer limit (net of tie benefits, or net of HQICC in the case of the Phase I/II HVDC-TF), then the capacity offers from those resources shall be treated as capacity offers in the modeled Capacity Zone associated with that interface. Where the amount of capacity offered from New Import Capacity Resources and Existing Import Capacity Resources over an interface between the New England Control Area and an external Control Area is greater than that interface's approved capacity transfer limit (net of tie benefits, or net of HQICC in the case of the Phase I/II HVDC-TF), then the following provisions shall apply (separately for each such interface):

(i) For purposes of determining which capacity offers from the New Import Capacity Resources and Existing Import Capacity Resources over the interface shall clear and at what price, the offers over the interface shall be treated in the descending-clock auction as if they comprised a separately-modeled export-constrained capacity zone, with an aggregate supply curve consisting of the offers from the New Import Capacity Resources and Existing Import Capacity Resources over the interface.

(ii) The amount of capacity offered over the interface that will be included in the aggregate supply curve of the modeled Capacity Zone associated with the interface shall be the lesser of the following two quantities: the amount of capacity offered from New Import Capacity Resources

and Existing Import Capacity Resources over the interface; and the interface's approved capacity transfer limit (net of tie benefits, or net of HQICC in the case of the Phase I/II HVDC-TF).

(iii) The Forward Capacity Auction for New Import Capacity Resources and Existing Import Capacity Resources over the interface is concluded when the following two conditions are both satisfied: the amount of capacity offered from New Import Capacity Resource and Existing Import Capacity Resources over the interface is less than or equal to the interface's approved capacity transfer limit (net of tie benefits, or net of HQICC in the case of the Phase I/II HVDC-TF); and the Forward Capacity Auction is concluded in the modeled Capacity Zone associated with the interface.

(e) **Treatment of Export Capacity.** Any Export Bid or any Administrative Export De-List Bid that is used to export capacity through an export interface connected to an import-constrained Capacity Zone from another Capacity Zone, or through an export interface connected to the Rest-of-Pool Capacity Zone from an export-constrained Capacity Zone in the Forward Capacity Auction will be modeled in the Capacity Zone where the export interface that is identified in the Existing Capacity Qualification Package is located. The Export Bid or Administrative Export De-List Bid clears in the Capacity Zone where the Export Bid or Administrative Export De-List Bid is modeled.

(i) Then the MW quantity equal to the relevant Export Bid or Administrative Export De-List Bid from the resource associated with the Export Bid or Administrative Export De-List Bid will be de-listed in the Capacity Zone where the resource is located. If the export interface is connected to an import-constrained Capacity Zone, the MW quantity procured will be in addition to the amount of capacity determined by the Capacity Zone Demand Curve for the import-constrained Capacity Zone.

(ii) If the Export Bid or Administrative Export De-List Bid does not clear, then the resource associated with the Export Bid or Administrative Export De-List Bid will not be de-listed in the Capacity Zone where the resource is located.

III.13.2.3.4. Determination of Final Capacity Zones.

(a) For all Forward Capacity Auctions up to and including the sixth Forward Capacity Auction (for the Capacity Commitment Period beginning June 1, 2015), after the Forward Capacity Auction is concluded for all modeled Capacity Zones, the final set of distinct Capacity Zones that will be used for all

purposes associated with the relevant Capacity Commitment Period, including for the purposes of reconfiguration auctions and Capacity Supply Obligation Bilaterals, shall be those having distinct Capacity Clearing Prices as a result of constraints between modeled Capacity Zones binding in the running of the Forward Capacity Auction. Where a modeled constraint does not bind in the Forward Capacity Auction, and as a result adjacent modeled Capacity Zones clear at the same Capacity Clearing Price, those modeled Capacity Zones shall be a single Capacity Zone used for all purposes of the relevant Capacity Commitment Period, including for the purposes of reconfiguration auctions and Capacity Supply Obligation Bilaterals.

(b) For all Forward Capacity Auctions beginning with the seventh Forward Capacity Auction (for the Capacity Commitment Period beginning June 1, 2016) the final set of distinct Capacity Zones that will be used for all purposes associated with the relevant Capacity Commitment Period, including for the purposes of reconfiguration auctions and Capacity Supply Obligation Bilaterals, shall be those described in Section III.12.4.

III.13.2.4. Forward Capacity Auction Starting Price and the Cost of New Entry.
The Forward Capacity Auction Starting Price is max [1.6 multiplied by Net CONE, CONE]. References in this Section III.13 to the Forward Capacity Auction Starting Price shall mean the Forward Capacity Auction Starting Price for the Forward Capacity Auction associated with the relevant Capacity Commitment Period.

CONE for the Forward Capacity Auction for the Capacity Commitment Period beginning on June 1, 2021 is $11.35/kW-month.

Net CONE for the Forward Capacity Auction for the Capacity Commitment Period beginning on June 1, 2021 is $8.04/kW-month.

CONE and Net CONE shall be recalculated for the Capacity Commitment Period beginning on June 1, 2025 and no less often than once every three years thereafter. Whenever these values are recalculated, the ISO will review the results of the recalculation with stakeholders and the new values will be filed with the Commission prior to the Forward Capacity Auction in which the new value is to apply.

Between recalculations, CONE and Net CONE will be adjusted for each Forward Capacity Auction pursuant to Section III.A.21.1.2(e). Prior to applying the annual adjustment for the Capacity

Commitment Period beginning on June 1, 2019, Net CONE will be reduced by $0.43/kW-month to reflect the elimination of the PER adjustment. The adjusted CONE and Net CONE values will be published on the ISO's web site.

III.13.2.5. Treatment of Specific Offer and Bid Types in the Forward Capacity Auction.

III.13.2.5.1. Offers from New Generating Capacity Resources, New Import Capacity Resources, and New Demand Capacity Resources.

A New Capacity Offer (other than one from a Conditional Qualified New Resource) clears (receives a Capacity Supply Obligation for the associated Capacity Commitment Period) in the Forward Capacity Auction if the Capacity Clearing Price is greater than or equal to the price specified in the offer, except possibly as a result of the Capacity Rationing Rule described in Section III.13.2.6. An offer from a Conditional Qualified New Resource clears (receives a Capacity Supply Obligation for the associated Capacity Commitment Period) in the Forward Capacity Auction, except possibly as a result of the Capacity Rationing Rule described in Section III.13.2.6, if all of the following conditions are met: (i) the Capacity Clearing Price is greater than or equal to the price specified in the offer; (ii) capacity from that resource is considered in the determination of clearing as described in Section III.13.2.3.2(f); and (iii) such offer minimizes the costs for the associated Capacity Commitment Period, subject to Section III.13.2.7.7(c).

The amount of capacity that receives a Capacity Supply Obligation through the Forward Capacity Auction shall not exceed the quantity of capacity offered from the New Generating Capacity Resource, New Import Capacity Resource, or New Demand Capacity Resource at the Capacity Clearing Price.

III.13.2.5.2. Bids and Offers from Existing Generating Capacity Resources, Existing Import Capacity Resources, and Existing Demand Capacity Resources.

III.13.2.5.2.1. Permanent De-List Bids and Retirement De-List Bids.

(a) Except as provided in Section III.13.2.5.2.5, a Permanent De-List Bid, Retirement De-List Bid or Proxy De-List Bid clears in the Forward Capacity Auction (does not receive a Capacity Supply Obligation) if the Capacity Clearing Price is less than or equal to the price specified in the bid, except possibly as a result of the Capacity Rationing Rule described in Section III.13.2.6.

(b) Unless the capacity has been retained for reliability pursuant to Section III.13.2.5.2.5, if all or part of a resource with a Permanent De-List Bid or Retirement De-List Bid does not clear in the Forward Capacity Auction (receives a Capacity Supply Obligation), the Lead Market Participant shall enter the uncleared portion of the bid into the qualification process for the following Forward Capacity Auction as described in Section III.13.1.2.3.1.5.

(c) If the Capacity Clearing Price is greater than the price specified in a de-list bid submitted by a Lead Market Participant that elected conditional treatment for the de-list bid pursuant to Section III.13.1.2.4.1(b), and there is an associated Proxy De-List Bid that does not clear (receives a Capacity Supply Obligation), the resource will receive a Capacity Supply Obligation at the Capacity Clearing Price.

(d) The process by which the primary auction is cleared (but not the compilation of offers and bids pursuant to Sections III.13.2.3.1 and III.13.2.3.2) will be repeated after the substitution auction is completed if one of the following conditions is met: (1) if any Proxy De-List Bid entered as a result of a Lead Market Participant electing to retire pursuant to Section III.13.1.2.4.1(a) does not clear (receives a Capacity Supply Obligation) in the first run of the primary auction-clearing process and retains some portion of its Capacity Supply Obligation in the substitution auction; or (2) if any Proxy De-List Bid entered as a result of a Lead Market Participant electing conditional treatment pursuant to Section III.13.1.2.4.1(b) does not clear (receives a Capacity Supply Obligation) in the first run of the primary auction-clearing process, the de-list bid submitted by the Lead Market Participant is at or above the Capacity Clearing Price, and the Proxy De-List Bid retains some portion of its Capacity Supply Obligation in the substitution auction. The second run of the primary auction-clearing process: (i) excludes all Proxy De-List Bids, (ii) includes the offers and bids of resources compiled pursuant to Section III.13.2.3.2 that did not receive a Capacity Supply Obligation in the first run of the primary auction-clearing process, excluding the offers, or portion thereof, associated with resources that acquired a Capacity Supply Obligation in the substitution auction, and (iii) includes the capacity of resources, or portion thereof, that retain a Capacity Supply Obligation after the first run of the primary auction-clearing process and the substitution auction. The second run of the primary auction-clearing process shall not affect the Capacity Clearing Price of the Forward Capacity Auction (which is established by the first run of the primary auction-clearing process).

(e) Resources (other than those still subject to a multi-year Capacity Commitment Period election as described in Sections III.13.1.1.2.2.4 and III.13.1.4.1.1.2.7) that receive a Capacity Supply Obligation as a

result of the first run of the primary auction-clearing process shall be paid the Capacity Clearing Price during the associated Capacity Commitment Period. Where the second run of the primary auction-clearing process procures additional capacity, the resulting price, paid during the associated Capacity Commitment Period (and subsequent Capacity Commitment Periods, as elected pursuant to Section III.13.1.1.2.2.4 or Section III.13.1.4.1.1.2.7) to the additionally procured capacity, shall be equal to or greater than the adjusted price resulting from the first run of the primary auction-clearing process for that Capacity Zone.

III.13.2.5.2.2. Static De-List Bids and Export Bids.

Except as provided in Section III.13.2.5.2.5, a Static De-List Bid or an Export Bid clears in the Forward Capacity Auction (does not receive a Capacity Supply Obligation for the associated Capacity Commitment Period) if the Capacity Clearing Price is less than or equal to the price specified in the bid, except possibly as a result of the Capacity Rationing Rule described in Section III.13.2.6.

III.13.2.5.2.3. Dynamic De-List Bids.

A Dynamic De-List Bid clears in the Forward Capacity Auction (does not receive a Capacity Supply Obligation for the associated Capacity Commitment Period) if the Capacity Clearing Price is less than or equal to the price specified in the bid, except possibly as a result of the Capacity Rationing Rule described in Section III.13.2.6. If more Dynamic De-List Bids are submitted at a price than are needed to clear the market, such Dynamic De-List Bids shall be cleared pro-rata, but in no case less than a resource's Rationing Minimum Limit.

III.13.2.5.2.4. Administrative Export De-List Bids.

An Administrative Export De-List Bid clears in the Forward Capacity Auction (does not receive a Capacity Supply Obligation for the associated Capacity Commitment Period) regardless of the Capacity Clearing Price.

III.13.2.5.2.5. Reliability Review.

The ISO shall review each Retirement De-List Bid, Permanent De-List Bid, Static De-List Bid, Export Bid, Administrative Export De-List Bid, Dynamic De-List Bid, and substitution auction demand bid to determine whether the capacity associated with that bid is needed for reliability reasons during the Capacity Commitment Period associated with the Forward Capacity Auction; Proxy De-List Bids shall not be reviewed.

(a) The reliability review of de-list bids will be conducted in descending price order using the price as finalized during qualification or as otherwise directed by the Commission. De-list bids with the same price will be reviewed in the order that produces the least negative impact to reliability; where bids are the same price and provide the same impact to reliability, they will be reviewed based on their submission time. If de-list bids with the same price are from a single generating station, they will be reviewed in an order that seeks to provide (1) the least-cost solution under Section III.13.2.5.2.5.1(d) and (2) the minimum aggregate quantity required for reliability from the generating station. The reliability review of substitution auction demand bids that would otherwise clear will be conducted in order beginning with the resource whose cleared bids contribute the greatest amount to social surplus. The capacity associated with a bid shall be deemed needed for reliability reasons if the absence of the capacity would result in the violation of any NERC or NPCC criteria, or ISO New England System Rules. Bids shall only be rejected pursuant to this Section III.13.2.5.2.5 for the sole purpose of addressing a local reliability issue, and shall not be rejected solely on the basis that acceptance of the bid may result in the procurement of less capacity than the Installed Capacity Requirement (net of HQICCs) or the Local Sourcing Requirement for a Capacity Zone.

(b) If a Retirement De-List Bid, Permanent De-List Bid, Static De-List Bid, Export Bid, Administrative Export De-List Bid, or Dynamic De-List Bid would otherwise clear in the Forward Capacity Auction, but the ISO has determined that some or all of the capacity associated with the de-list bid is needed for reliability reasons, then the de-list bid having capacity needed for reliability will not clear in the Forward Capacity Auction. If the ISO has determined that some or all of the capacity associated with a substitution auction demand bid that would otherwise clear is needed for reliability reasons, then the entire demand bid will not be further included in the substitution auction.

(c) The Lead Market Participant shall be notified that its bid did not clear for reliability reasons at the later of: (i) immediately after the end of the Forward Capacity Auction round in which the auction price reaches the price of the de-list bid; or (ii) as soon as practicable after the time at which the ISO has determined that the bid must be rejected for reliability reasons. In no event, however, shall a Lead Market Participant be notified that a bid submitted pursuant to Section III.13.1.2.5 and accepted in the qualification process for an Existing Generating Capacity Resource did not clear for reliability reasons if the associated New Generating Capacity Resource remains in the Forward Capacity Auction. In such a case, the Lead Market Participant shall be notified that its bid did not clear for reliability reasons at the later of: (i) immediately after the end of the Forward Capacity Auction round in which the auction price reaches the price of the bid; (ii) immediately after the end of the Forward Capacity Auction round in

which the associated New Generating Capacity Resource is fully withdrawn (that is, the Forward Capacity Auction reaches a price at which the resource's New Capacity Offer is zero capacity); or (iii) as soon as practicable after the time at which the ISO has determined that the bid must be rejected for reliability reasons.

(d) A resource that has a de-list bid rejected for reliability reasons shall be compensated pursuant to the terms set out in Section III.13.2.5.2.5.1 and shall have a Capacity Supply Obligation as described in Section III.13.6.1.

(e) The ISO shall review the results of each annual reconfiguration auction and determine whether the reliability need which caused the ISO to reject the de-list bid has been met through the annual reconfiguration auction. The ISO may also attempt to address the reliability concern through other reasonable means (including transmission enhancements).

(f) If the reliability need that caused the ISO to reject a de-list bid is met through a reconfiguration auction or other means, the resource shall retain its Capacity Supply Obligation through the end of the Capacity Commitment Period for which it was retained for reliability (provided that resources that have Permanent De-List Bids or Retirement De-List Bids rejected for reliability shall be permanently de-listed or retired as of the first day of the subsequent Capacity Commitment Period (or earlier if the resource sheds the entirety of the Capacity Supply Obligation as described in Section III.13.2.5.2.5.3(a)(ii) or Section III.13.2.5.2.5.3(b)(ii))).

(g) If a Permanent De-List Bid or a Retirement De-List Bid is rejected for reliability reasons, and the reliability need is not met through a reconfiguration auction or other means, that resource, or portion thereof, as applicable, is no longer eligible to participate as an Existing Capacity Resource in any reconfiguration auction, Forward Capacity Auction or Capacity Supply Obligation Bilateral for that and subsequent Capacity Commitment Periods. If the resource, or portion thereof, continues to be needed for reliability reasons, it shall be counted as capacity in the Forward Capacity Auction and shall be compensated as described in Section III.13.2.5.2.5.1.

(h) The ISO shall review with the Reliability Committee (i) the status of any prior rejected de-list bids reported to the Commission in an FCA results filing pursuant to Section 13.8.2, and (ii) the status of any Retirement De-List Bid or Permanent De-List Bid that has been rejected for reliability reasons and

has elected to continue to operate, prior to the New Capacity Qualification Deadline in accordance with Section 4.1(c) of Attachment K of the ISO OATT.

If an identified reliability need results in the rejection of a Retirement De-List Bid, Permanent De-List Bid, Export Bid, Administrative Export De-List Bid, Static De-List Bid, or Dynamic De-List Bid while executing an FCA, the ISO shall (i) review each specific reliability need with the Reliability Committee in accordance with the timing provided for in the ISO New England Operating Documents and, (ii) update the current system Needs Assessments pursuant to Section 4.1(c) of Attachment K of the ISO OATT. This review and update will follow ISO's filing of the FCA results with the Commission pursuant to Section 13.8.2.

III.13.2.5.2.5A Fuel Security Reliability Review

(a) This Section III.13.2.5.2.5A will remain in effect for the 2022/23 and 2023/24 Capacity Commitment Periods, after which this Section III.13.2.5.2.5A will sunset.

(b) This Section III.13.2.5.2.5A will apply to (i) Retirement De-List Bids, (ii) substitution auction demand bids, and (iii) bilateral transactions and reconfiguration auctions demand bids submitted by an Existing Generating Capacity Resource that has been identified as being needed for fuel security during a Forward Capacity Auction. Terms set out in this Section III.13.2.5.2.5A will apply only for the period and resources described within this Section III.13.2.5.2.5A. Where the terms and conditions in this Section III.13.2.5.2.5A differ from terms otherwise set out in Section III.13, the terms of this Section III.13.2.5.2.5A will control for the period and circumstances described in Section III.13.2.5.2.5A.

(c) A fuel security reliability review for the Forward Capacity Market will be performed pursuant to Appendix L to Section III of the Tariff, and in accordance with the inputs and methodology set out to establish the fuel security reliability standard in Appendix I of Planning Procedure No. 10.

(d) For fuel security reliability reviews performed for the primary Forward Capacity Auction, the fuel security reliability review will be performed after the Existing Capacity Retirement Deadline and conducted in descending price order using the price as submitted in the Retirement De-List Bids. Bids with the same price will be reviewed in the order that produces the least negative impact to reliability. Where multiple bids have the same price and the retirement of the Existing Generating Capacity Resources would have the same impact to reliability, they will be reviewed based on their submission

time. If bids with the same price are from a single generating station, they will be reviewed in an order that seeks to provide (1) the least-cost solution under Section III.13.2.5.2.5.1(d), and (2) the minimum aggregate quantity required for reliability from the generating station. An Existing Generating Capacity Resource may be needed for both fuel security and for transmission security pursuant to Section III.13.2.5.2.5. The fuel security reliability review will be performed in advance of the reliability review for transmission security. Where an Existing Generating Capacity Resource is needed for both fuel security reasons pursuant to this Section III.13.2.5.2.5A, and transmission security reliability reasons pursuant to Section III.13.2.5.2.5, the generator will be retained for fuel security for purposes of cost allocation.

(e) If an Existing Generating Capacity Resource is identified as being needed for fuel security reasons, and the reliability need is not met through a reconfiguration auction or other means, that resource, or portion thereof, as applicable may not participate in Annual Reconfiguration Auctions for the Capacity Commitment Period(s) for which it is needed for fuel security, or earlier 2022/23 and 2023/24 Capacity Commitment Periods. Such an Existing Generating Capacity Resource that is identified as being needed for fuel security may participate in monthly bilateral transactions and monthly reconfiguration auctions, but may not submit monthly bilateral transactions for December, January or February, or demand bids for the December, January, or February monthly reconfiguration auctions for any period for which they have been identified as being needed for fuel security.

(f) Participants that have submitted a Retirement De-List Bid will be notified by ISO New England if their resource is needed for fuel security reliability reasons no later than 90 days after the Existing Capacity Retirement Deadline. Participants that have submitted a substitution auction demand bid, and where the demand bid has been rejected for reliability reasons, will be notified after the relevant Forward Capacity Auction has been completed.

(g) Where a Retirement De-List Bid would otherwise clear in the Forward Capacity Auction, but the ISO has determined that some or all of the capacity associated with the de-list bid is needed for fuel security reliability reasons, the provisions of III.13.2.5.2.5(b) shall apply.

(h) Existing Generating Capacity Resources that have had their Retirement De-list Bid rejected for fuel security reliability reasons and that do not elect to unconditionally or conditionally retire shall be eligible for compensation pursuant to Section III.13.2.5.2.5.1, except that the difference between payments based on resource de-list bids or cost-of-service compensation as detailed in Section III.13.2.5.2.5.1 and

payments based on the Capacity Clearing Price for the Forward Capacity Market under this Section III.13.2.5.2.5.1 shall be allocated on a regional basis to Real Time Load Obligation, excluding Real-Time Load Obligation associated with Dispatchable Asset Related Demand Resources (DARD Pumps and other electric storage based DARDs) and Real-Time Load Obligation associated with Coordinated External Transactions, allocated and collected over a 12 month period. Resources that that are identified as needed for fuel security reliability reasons will have their capacity entered into the Forward Capacity Auction pursuant to III.13.2.5.2.5(g) and III.13.2.3.2(b).

(i) Where an Existing Generating Capacity Resource elects a cost-of-service agreement pursuant to Section III.13.2.5.2.5.1 to address a fuel security reliability need, the term of such a cost-of-service agreement may not exceed two years, including renewal through evergreen provisions.

(j) The ISO shall perform an annual reevaluation of any Existing Generating Capacity Resources retained for reliability under this provision. If a resource associated with a Retirement De-List Bid that was rejected for reliability reasons pursuant to this section, is found to no longer be needed for fuel security, and is not needed for another reliability reason pursuant to Section III.13.2.5.2.5, the resource will be retired from the system as described in Section III.13.2.5.2.5.3(a)(1). In no case will a resource retained for fuel security be retained for fuel security beyond June 1, 2024.

(k) The ISO will review Retirement De-List Bids rejected for fuel security reliability reasons with the Reliability Committee in the same manner as described in Section III.13.2.5.2.5(h).

III.13.2.5.2.5.1. Compensation for Bids Rejected for Reliability Reasons.

(a) In cases where a Static De-List Bid, Export Bid, Administrative Export De-List Bid, Dynamic De-List Bid, partial Permanent De-List Bid, or partial Retirement De-List Bid has been rejected for reliability reasons pursuant to Sections III.13.1.2.3.1.5.1 or III.13.2.5.2.5, the resource will be paid by the ISO in the same manner as all other capacity resources, except that payment shall be made on the basis of its de-list bid as accepted for the Forward Capacity Auction for the relevant Capacity Commitment Period instead of the Forward Capacity Market Clearing Price. Under this Section, accepted Dynamic De-List Bids filed with the Commission as part of the FCA results filing are subject to review and approval by the Commission pursuant to the “just and reasonable” standard of Section 205 of the Federal Power Act. If a resource with a partial Permanent De-List Bid or partial Retirement De-List Bid continues to be needed for reliability in Capacity Commitment Periods following the Capacity Commitment Period for which the partial Permanent De-List Bid or partial Retirement De-List Bid was rejected, payment will continue to be pursuant to this Section III.13.2.5.2.5.1(a).

(b) In cases where a Permanent De-List Bid or a Retirement De-List Bid for the capacity of an entire resource has been rejected for reliability reasons pursuant to Section III.13.1.2.3.1.5.1 or III.13.2.5.2.5, the resource will be paid either (i) in the same manner as all other capacity resources, except that payment shall be made on the basis of its Commission-approved Permanent De-List Bid or Commission-approved Retirement De-List Bid for the relevant Capacity Commitment Period instead of the Forward Capacity Market Clearing Price or (ii) under the terms of a cost-of-service agreement pursuant to Section III, Appendix I. Resources must notify the ISO of their election within six months after the ISO files the results of the relevant Forward Capacity Auction with the Commission. A resource that has had a Permanent De-List Bid or Retirement De-List Bid rejected for reliability reasons and does not notify the ISO of its election as described in this paragraph will be paid on the basis of the resource's Commission-approved Permanent De-List Bid or Commission-approved Retirement De-List Bid. Cost-of-service agreements must be filed with and approved by the Commission, and cost-of-service compensation may not commence until the Commission has approved the use of cost-of-service rates for the unit in question or has accepted the use of the cost-of-service rates subject to refund while the rate is reviewed. In no event will payment under the cost-of-service agreement start prior to the start of the relevant Capacity Commitment Period for which the Permanent De-List Bid or Retirement De-List Bid was submitted. If a resource continues to be needed for reliability in Capacity Commitment Periods following the Capacity Commitment Period for which the Permanent De-List Bid or Retirement De-List Bid was rejected, payment will continue to be pursuant to this Section III.13.2.5.2.5.1(b). Resources that elect payment based on the Commission-approved Permanent De-List Bid or Commission-approved Retirement De-List Bid may file with the Commission pursuant to Section 205 of the Federal Power Act to update its Permanent De-List Bid or Retirement De-List Bid if the unit is retained for reliability for a period longer than the Capacity Commitment Period for which the Permanent De-List Bid or Retirement De-List Bid was originally submitted.

(c) The difference between payments based on resource de-list bids or cost-of-service compensation as detailed in this Section III.13.2.5.2.5.1 and payments based on the market clearing price for the Forward Capacity Market under this Section III.13.2.5.2.5.1 shall be allocated to Regional Network Load within the affected Reliability Region.

(d) **Compensation for Existing Generating Capacity Resources at Stations with Common Costs that are Retained for Reliability**. If a Static De-List Bid, Permanent De-List Bid, or Retirement De-List Bid from an Existing Generating Capacity Resource that is associated with a Station having Common Costs is rejected for reliability reasons, the Existing Generating Capacity Resource will be paid as follows: (i) if one or more Existing Generating Capacity Resources at the Station assume a Capacity Supply Obligation through the normal clearing of the Forward Capacity Auction and one or more Existing Generating Capacity Resources are retained for reliability, then the Existing Generating Capacity Resources retained for reliability will be paid the sum of the Asset-Specific Going Forward Costs for the assets comprising that Existing Generating Capacity Resource; or (ii) if no Existing Generating Capacity Resources at the Station assumes a Capacity Supply Obligation through the normal clearing of the Forward Capacity Auction and one or more Existing Generating Capacity Resources are retained for reliability, then each Existing Generating Capacity Resource retained for reliability will be paid the sum of the Asset-Specific Going Forward Costs for the assets associated with that Existing Generating Capacity Resource plus a portion of the Station Going Forward Common Costs (such that the full amount of Station Going Forward Common Costs are allocated to the Existing Generating Capacity Resources retained for reliability).

(e) If ISO-NE is a party to a cost-of-service agreement filed after January 1, 2019 that changes any resource performance-related obligations contained in Section III, Appendix I (provided that those obligations are different than the obligations of an Existing Generating Capacity Resource with a Capacity Supply Obligation), no later than 30 days after such agreement is filed with the Commission, ISO-NE shall provide to stakeholders quantitative and qualitative information on the need for, and the impacts of, the proposed changes.

III.13.2.5.2.5.2. Incremental Cost of Reliability Service From Permanent De-List Bid or Retirement De-List Bid Resources.

In cases where an Existing Generating Capacity Resource or Existing Demand Capacity Resource has had a Permanent De-List Bid or Retirement De-List Bid for the entire resource rejected for reliability reasons pursuant to Sections III.13.1.2.3.1.5.1 or III.13.2.5.2.5, does not elect to retire pursuant to Section III.13.1.2.3.1.5.1(d), and must make a capital improvement to the unit to remain in operation in order to continue to operate to meet the reliability need identified by the ISO, the resource may make application to the Commission pursuant to Section 205 of the Federal Power Act to receive just and reasonable compensation of the capital investment pursuant to the following:

(a) **Notice to State Utility Commissions, the ISO and Stakeholder Committees of Expectation that a Capital Expense will be Necessary to Meet the Reliability Need Identified by the ISO**: A resource seeking to avail itself of the recovery mechanism provided in this Section must notify the state utility commissions in the states where rate payers will fund the capital improvement, the ISO, and the Participants Committee of its intent to make the capital expenditure and the need for the expenditure. This notification must be made at least 120 days prior to the resource making the capital expenditure.

(b) **Required Showing Made to the Federal Energy Regulatory Commission**: In order to receive just and reasonable compensation for a capital expenditure under this Section, a resource must file an explanation of need with the Commission that explains why the capital expenditure is necessary in order to meet the reliability need identified by the ISO. This showing must demonstrate that the expenditure is reasonably determined to be the least-cost commercially reasonable option consistent with Good Utility Practice to meet the reliability need identified by the ISO. If the resource elects cost-of-service treatment pursuant to Section III.13.2.5.2.5.1(b), the Incremental Cost of Reliability Service filing described in this Section must be made separately from and may be made in advance of the resource's cost-of-service filing.

(c) **Allocation:** Costs of capital expenditures approved by the Commission under this provision shall be allocated to Regional Network Load within the affected Reliability Region.

III.13.2.5.2.5.3. Retirement and Permanent De-Listing of Resources.

(a)(i) A resource, or portion thereof, will be retired coincident with the commencement of the relevant Capacity Commitment Period, or earlier as described in Section III.13.2.5.2.5.3(a)(ii), if the resource: (1) submitted a Retirement De-List Bid at or above the Forward Capacity Auction Starting Price and was not retained for reliability pursuant to Section III.13.1.2.3.1.5.1; (2) submitted a Permanent De-List Bid or Retirement De-List Bid, elected to retire pursuant to Section III.13.1.2.4.1(a), and was not retained for reliability pursuant to Section III.13.1.2.3.1.5.1; (3) elected conditional treatment pursuant to Section III.13.1.2.4.1(b) for a Retirement De-List Bid with a submitted price at or above the Capacity Clearing Price and was not retained for reliability pursuant to Section III.13.1.2.3.1.5.1; or (4) had a Commission-approved Retirement De-List Bid clear in the Forward Capacity Auction. In the case of a Retirement De-List Bid rejected for reliability, if the reliability need that resulted in the rejection for reliability is met, the resource, or portion thereof, will be retired coincident with the end of Capacity Supply Obligation (or earlier as described in Section III.13.2.5.2.5.3(a)(ii)) unless the Commission directs that the obligation to retire be removed or the retirement date extended as part of an Incremental Cost of Reliability Service

filing made pursuant to Section III.13.2.5.2.5.2. The interconnection rights, or relevant portion thereof, for the resource will terminate and the status of the resource, or portion thereof, will be converted to retired on the date of retirement, consistent with the provisions of Schedules 22 and 23 of the OATT.

(a)(ii) A resource, or portion thereof, that is to be retired pursuant to Section III.13.2.5.2.5.3(a)(i) may retire the resource, or portion thereof, earlier than the Capacity Commitment Period for which its Retirement De-List Bid was submitted if it is able to transfer the relevant Capacity Supply Obligation of the resource to another resource through one or more approved Capacity Supply Obligation Bilateral transactions as described in Section III.13.5.1 or reconfiguration auctions as described in Section III.13.4.1. A resource, or portion thereof, electing to retire pursuant to this provision must notify the ISO in writing of its election to retire and the date of retirement. The interconnection rights, or relevant portion thereof, for the resource will terminate and the status of the resource, or portion thereof, will be converted to retired on the date of retirement, consistent with the provisions of Schedules 22 and 23 of the OATT.

(b)(i) A resource, or portion thereof, will be permanently de-listed from the Forward Capacity Market as of the relevant Capacity Commitment Period, or earlier as described in Section III.13.2.5.2.5.3(b)(ii), if the resource: (1) submitted an Internal Market Monitor-approved Permanent De-List Bid at or above the Forward Capacity Auction Starting Price and was not retained for reliablity pursuant to Section III.13.1.2.3.1.5.1; (2) elected conditional treatment pursuant to Section III.13.1.2.4.1(b) for a Permanent De-List Bid with a submitted price at or above the Capacity Clearing Price and was not retained for reliability pursuant to Section III.13.1.2.3.1.5.1; or (3) had a Commission-approved Permanent De-List Bid clear in the Forward Capacity Auction. The CNR Capability interconnection rights, or relevant portion thereof, for the resource will be adjusted downward to reflect the Permanent De-List Bid, consistent with the provisions of Schedules 22 and 23 of the OATT. A resource that permanently de-lists pursuant to this Section III.13.2.5.2.5.3(b)(i) is precluded from subsequent participation in the Forward Capacity Market unless it qualifies as a New Generating Capacity Resource pursuant to Section III.13.1.1.1.2.

(b)(ii) A resource, or portion thereof, that is to be permanently de-listed pursuant to Section III.13.2.5.2.5.3(b)(i) may be permanently de-listed earlier than the Capacity Commitment Period for which its Permanent De-List Bid was submitted if it is able to transfer the entire Capacity Supply Obligation of the resource to another resource through one or more approved Capacity Supply Obligation Bilateral transactions as described in Section III.13.5.1 or reconfiguration auctions as described in Section III.13.4.

(c) A resource that has never been counted as a capacity resource may retire the asset by notifying the ISO in writing of its election to retire and the date of retirement. The date specified for retirement is subject to the limit for resource inactivity set out in Section III.13.2.5.2.5.3(d). The interconnection rights for the resource will terminate and the status of the resource will be converted to retired on the date of retirement.

(d) A resource that does not operate commercially for a period of three calendar years will be deemed by the ISO to be retired. The interconnection rights for the unit will terminate and the status of the unit will be converted to retired on the date of retirement. Where a generator has submitted an application to repower under Schedule 22 or 23 of the OATT, the current interconnection space will be maintained beyond the three years unless the application under Schedule 22 or 23 is withdrawn voluntarily or by the operation of those provisions. Where an application is withdrawn under Schedule 22 or 23, the three year period will be calculated from the last day of commercial operation of the resource.

III.13.2.6. Capacity Rationing Rule.

Except for Dynamic De-List Bids, Export Bids, and offers from New Import Capacity Resources that are subject to rationing pursuant to Section III.13.1.3.5.8 and Existing Import Capacity Resources that are subject to rationing pursuant to Section III.13.1.3.3.A, offers and bids in the Forward Capacity Auction must clear or not clear in whole, unless the offer or bid specifically indicates that it may be rationed. A resource may elect to be rationed to its Rationing Minimum Limit pursuant to Sections III.13.1.1.2.2.3 and III.13.1.2.1.2. Offers from New Import Capacity Resources and Existing Import Capacity Resources will not be rationed where such rationing would violate any applicable physical minimum flow requirements on the associated interface. Export Bids may elect to be rationed generally, but regardless of such election will always be subject to potential rationing where the associated external interface binds. If more Dynamic De-List Bids are submitted at a price than are needed to clear the market, the bids shall be cleared pro-rata, subject to honoring the Rationing Minimum Limit of the resources. Where an offer or bid may be rationed, such rationing may not result in procuring an amount of capacity that is below the associated resource's Rationing Minimum Limit.

III.13.2.7. Determination of Capacity Clearing Prices.

The Capacity Clearing Price in each Capacity Zone shall be the price established by the descending clock auction as described in Section III.13.2.3, subject to the other provisions of this Section III.13.2.7. The Capacity Clearing Price for the Rest-of-Pool Capacity Zone and the Capacity Clearing Price for each

import-constrained Capacity Zone shall not exceed the Forward Capacity Auction Starting Price. The Capacity Clearing Price for an export-constrained Capacity Zone shall not be less than zero.

III.13.2.7.1. Import-Constrained Capacity Zone Capacity Clearing Price Floor.

The Capacity Clearing Price in an import-constrained Capacity Zone shall not be lower than the Capacity Clearing Price in the Rest-of-Pool Capacity Zone. If after the Forward Capacity Auction is conducted, the Capacity Clearing Price in an import-constrained Capacity Zone is less than the Capacity Clearing Price in the Rest-of-Pool Capacity Zone, all resources clearing in the import-constrained Capacity Zone shall be paid based on the Capacity Clearing Price in the Rest-of-Pool Capacity Zone during the associated Capacity Commitment Period.

III.13.2.7.2. Export-Constrained Capacity Zone Capacity Clearing Price Ceiling.

The Capacity Clearing Price in an export-constrained Capacity Zone shall not be higher than the Capacity Clearing Price in the Rest-of-Pool Capacity Zone.

The Capacity Clearing Price in a nested Capacity Zone shall not be higher than the Capacity Clearing Price in the Capacity Zone within which it is located.

III.13.2.7.3. [Reserved.]

III.13.2.7.3A. Treatment of Imports.

At the Capacity Clearing Price, if the amount of capacity offered from New Import Capacity Resources and Existing Import Capacity Resources over an interface between an external Control Area and the New England Control Area is greater than that interface's approved capacity transfer limit (net of tie benefits, or net of HQICC in the case of the Phase I/II HVDC-TF):

> (a) the full amount of capacity offered at that price from Existing Import Capacity Resources associated with contracts listed in Section III.13.1.3.3.A(c) shall clear, unless that amount of capacity is greater than the interface's approved capacity transfer limit (net of tie benefits, or net of HQICC in the case of the Phase I/II HVDC-TF), in which case the capacity offered at that price from Existing Import Capacity Resources associated with contracts listed in Section III.13.1.3.3.A(c) shall be rationed such that the interface's approved capacity transfer limit (net of tie benefits, or net of HQICC in the case of the Phase I/II HVDC-TF) is not exceeded; and

(b) if there is space remaining over the interface after the allocation described in subsection (a) above, then the capacity offered at that price from New Import Capacity Resources and Existing Import Capacity Resources other than Existing Import Capacity Resources associated with the contracts listed in Section III.13.1.3.3.A(c) will be rationed such that the interface's approved capacity transfer limit (net of tie benefits, or net of HQICC in the case of the Phase I/II HVDC-TF) is not exceeded. If the capacity offered at that price by any single New Import Capacity Resource or Existing Import Capacity Resource that is not associated with the contracts listed in Section III.13.1.3.3.A(c) is greater than the interface's approved capacity transfer limit (net of tie benefits, or net of HQICC in the case of the Phase I/II HVDC-TF), then the capacity offered by that resource that is above the interface's approved capacity transfer limit (net of tie benefits, or net of HQICC in the case of the Phase I/II HVDC-TF) shall not be included in the rationing.

III.13.2.7.4. Effect of Capacity Rationing Rule on Capacity Clearing Price.
Where the requirement that offers and bids clear or not clear in whole (Section III.13.2.6) prohibits the descending clock auction in its normal progression from clearing one or more Capacity Zones at the precise amount of capacity determined by the Capacity Zone Demand Curves specified in Section III.13.2.2, then the auctioneer shall analyze the aggregate supply curve to determine cleared capacity offers and Capacity Clearing Prices that seek to maximize social surplus for the associated Capacity Commitment Period. The clearing algorithm may result in offers below the Capacity Clearing Price not clearing, and in de-list bids below the Capacity Clearing Price clearing.

III.13.2.7.5. Effect of Decremental Repowerings on the Capacity Clearing Price.
Where the effect of accounting for certain repowering offers and bids (as described in Section III.13.2.3.2(e)) results in the auction not clearing at the lowest price for the required quantity of capacity, then the auctioneer will conduct additional auction rounds of the Forward Capacity Auction as necessary to minimize capacity costs.

III.13.2.7.6. Minimum Capacity Award.
Each offer (excluding offers from Conditional Qualified New Resources that do not satisfy the conditions specified in Sections III.13.2.5.1(i)-(iii)) clearing in the Forward Capacity Auction shall be awarded a Capacity Supply Obligation at least as great as the amount of capacity offered at the End-of-Round Price in the final round of the Forward Capacity Auction. For Intermittent Power Resources, the Capacity

Supply Obligation for months in the winter period (as described in Section III.13.1.5) shall be adjusted based on its winter Qualified Capacity as determined pursuant to Section III.13.1.1.2.2.6 and Section III.13.1.2.2.2.

III.13.2.7.7. Tie-Breaking Rules.

Where the provisions in this Section III.13.2 for clearing the Forward Capacity Auction (system-wide or in a single Capacity Zone) result in a tie – that is, where two or more resources offer sufficient capacity at prices that would clear the auction at the same minimum costs – the auctioneer shall apply the following rules (in sequence, as necessary) to determine clearing:

(a) [Reserved.]

(b) If multiple projects may be rationed, they will be rationed proportionately.

(c) Where clearing either the offer associated with a resource with a higher queue priority at a Conditional Qualified New Resource's location or the offer associated with the Conditional Qualified New Resource would result in equal costs, the offer associated with the resource with the higher queue priority shall clear.

(d) The offer associated with the Project Sponsor having the lower market share in the capacity auction (including Existing Generating Capacity Resources, Existing Import Capacity Resources, and Existing Demand Capacity Resources) shall be cleared.

III.13.2.8. Capacity Substitution Auctions.

III.13.2.8.1. Administration of Substitution Auctions.

Following the completion of the primary auction-clearing process of the Forward Capacity Auction as provided for in Section III.13.2, the ISO shall conduct a substitution auction, using a static double auction to clear supply offers (offers to assume a Capacity Supply Obligation) and demand bids (bids to shed a Capacity Supply Obligation). Supply offers and demand bids will be modeled in the Capacity Zone where the associated resources are electrically interconnected.

III.13.2.8.1.1. Substitution Auction Clearing and Awards.

The substitution auction shall maximize total social surplus as specified by the demand bids and supply offers used in the auction. The maximization is constrained as follows:

(i) By the external interface limits modeled in the primary auction-clearing process.

(ii) Such that the net cleared Capacity Supply Obligations (total acquired less total shed) in the substitution auction is equal to zero.

(iii) Such that, for each import-constrained Capacity Zone, if the zone's total Capacity Supply Obligations awarded in the primary auction-clearing process of the Forward Capacity Auction is less than the zone threshold quantity specified below, then the zone's net cleared Capacity Supply Obligations (total acquired less total shed) in the substitution auction is equal to zero; otherwise, the sum of the zone's total Capacity Supply Obligations awarded in the primary auction-clearing process and the zone's net cleared Capacity Supply Obligations (total acquired less total shed) in the substitution auction is greater than or equal to the zone threshold quantity specified below.

(iv) Such that, for each export-constrained Capacity Zone, if the zone's total Capacity Supply Obligations awarded in the primary auction-clearing process of the Forward Capacity Auction is greater than the zone threshold quantity specified below, then the zone's net cleared Capacity Supply Obligations (total acquired less total shed) in the substitution auction is equal to zero; otherwise, the sum of the zone's total Capacity Supply Obligations awarded in the primary auction-clearing process and the zone's net cleared Capacity Supply Obligations (total acquired less total shed) in the substitution auction is less than or equal to the zone threshold quantity specified below.

In applying constraint (iii), the zone threshold quantity for an import-constrained Capacity Zone shall be equal to the sum of its Capacity Zone Demand Curve truncation point quantity specified in Section III.13.2.2.2 and the total quantity of any Export Bids and any Administrative Export De-List Bids for which the exporting resource is located outside the import-constrained Capacity Zone, that are used to export capacity across an external interface connected to the import-constrained Capacity Zone, and that cleared in the primary auction-clearing process of the Forward Capacity Auction.

In applying constraint (iv), the zone threshold quantity for an export-constrained Capacity Zone shall be equal to its Capacity Zone Demand Curve truncation point quantity specified in Section III.13.2.2.3 less the total quantity of any Export Bids and any Administrative Export De-List Bids for which the exporting resource is located in the export-constrained Capacity Zone, including any Export Bids and any Administrative Export De-List Bids in an associated nested export-constrained Capacity Zone, that are

used to export capacity across an external interface connected to another Capacity Zone, and that cleared in the primary auction-clearing process of the Forward Capacity Auction.

In applying constraints (iii) and (iv), a zone's total Capacity Supply Obligations awarded in the primary auction-clearing process of the Forward Capacity Auction and net cleared Capacity Supply Obligations (total acquired less total shed) in the substitution auction shall include the Capacity Supply Obligations of Import Capacity Resources at each external interface connected to the Capacity Zone.

In applying constraints (iii) and (iv), a zone's total Capacity Supply Obligations awarded in the primary auction-clearing process of the Forward Capacity Auction shall include the Capacity Supply Obligations awarded to Proxy De-List Bids within the zone, and the zone's net cleared Capacity Supply Obligations (total acquired less total shed) in the substitution auction shall include the Capacity Supply Obligations shed from demand bids associated with Proxy De-List Bids within the zone.

In cases in which there are multiple clearing outcomes that would each maximize the substitution auction's objective, the following tie-breaking rules will apply in the following sequence: (i) non-rationable demand bids associated with Lead Market Participants having the largest total FCA Qualified Capacity of Existing Capacity Resources will be cleared first; and (ii) rationable supply offers will be cleared in proportion to their offer quantity.

For Intermittent Power Resources, other than those participating as the summer resource in a Composite FCM Transaction, the cleared award for supply offers and demand bids shall be adjusted for the months in the winter period (as described in Section III.13.1.5) using the ratio of the resource's cleared offer or bid amount divided by its FCA Qualified Capacity multiplied by its winter Qualified Capacity as determined pursuant to Section III.13.1.1.2.2.6 and Section III.13.1.2.2.2 after removing any portion of the resource's winter Qualified Capacity that is participating in a Composite FCM Transaction.

The cleared offer amount awarded to a Composite FCM Transaction in the substitution auction will be assigned to the summer and winter resources for their respective obligation months during the Capacity Commitment Period as described in Section III.13.1.5.

If, after the substitution auction, a resource has a Capacity Supply Obligation below its Economic Minimum Limit, it must meet the requirements of Section III.13.6.1.1.1.

III.13.2.8.1.2. Substitution Auction Pricing.

The substitution auction will specify clearing prices for Capacity Zones and external interfaces as follows.

For each import-constrained Capacity Zone, if the sum of the zone's total Capacity Supply Obligations awarded in the primary auction-clearing process of the Forward Capacity Auction and the zone's net cleared Capacity Supply Obligations (total acquired less total shed) in the substitution auction is greater than its zone threshold quantity specified in Section III.13.2.8.1.1, then supply offers and demand bids in the substitution auction in the import-constrained Capacity Zone shall be treated as offers and bids in the Rest-of-Pool Capacity Zone for purposes of determining substitution auction clearing prices.

For each export-constrained Capacity Zone,

(i) if the sum of the zone's total Capacity Supply Obligations, including Capacity Supply Obligations in a nested Capacity Zone, awarded in the primary auction-clearing process of the Forward Capacity Auction and the zone's net cleared Capacity Supply Obligations (total acquired less total shed) in the substitution auction including net cleared Capacity Supply Obligations in the nested Capacity Zone is less than its zone threshold quantity specified in Section III.13.2.8.1.1, then supply offers and demand bids in the substitution auction in the export-constrained Capacity Zone (excluding supply offers and demand bids in the nested Capacity Zone that are not treated as offers and bids in the export-constrained Capacity Zone pursuant to Section III.13.2.8.1.2(ii)) shall be treated as offers and bids in the Rest-of-Pool Capacity Zone for purposes of determining substitution auction clearing prices.

(ii) if the sum of a nested Capacity Zone's Capacity Supply Obligations awarded in the primary auction-clearing process of the Forward Capacity Auction and the nested Capacity Zone's net cleared Capacity Supply Obligations (total acquired less total shed) in the substitution auction is less than its zone threshold quantity specified in Section III.13.2.8.1.1, then supply offers and demand bids in the substitution auction in the nested Capacity Zone shall be treated as offers and bids in the export-constrained Capacity Zone within which the nested Capacity Zone is located, for purposes of determining substitution auction clearing prices.

The substitution auction clearing prices for the Rest-of-Pool Capacity Zone and for any constrained zones pooled with the Rest-of-Pool Capacity Zone for pricing purposes shall be determined by the price of the

demand bid or supply offer that is marginal. If a demand bid associated with a Proxy De-List Bid is marginal, then the substitution auction clearing prices shall be set equal to the Capacity Clearing Prices.

The substitution auction clearing price for a constrained Capacity Zone that is not pooled with the Rest-of-Pool Capacity Zone for pricing purposes shall be determined by the price of the demand bid or supply offer associated with the separately-priced constrained Capacity Zone that is marginal. If a demand bid associated with a Proxy De-List Bid is marginal, then the substitution auction clearing price shall be set equal to the Capacity Clearing Price for the constrained Capacity Zone.

The substitution auction clearing price for a nested export-constrained Capacity Zone that is not pooled with the export-constrained Capacity Zone in which it is located for pricing purposes shall be determined by the price of the demand bid or supply offer that is marginal in the nested export-constrained Capacity Zone. If a demand bid associated with a Proxy De-List Bid is marginal, then the substitution auction clearing price for the nested export-constrained Capacity Zone shall be equal to the Capacity Clearing Price for that nested export-constrained Capacity Zone.

If the net quantity of Capacity Supply Obligations awarded in the primary Forward Capacity Auction and substitution auction over an interface between the New England Control Area and an external Control Area is less than that interface's approved capacity transfer limit (net of tie benefits, or net of HQICC in the case of the Phase I/II HVDC-TF), then supply offers and demand bids in the substitution auction at the interface shall be treated as offers and bids in the modeled Capacity Zone associated with that interface for purposes of determining substitution auction clearing prices.

If the net quantity of Capacity Supply Obligations awarded in the primary Forward Capacity Auction and substitution auction over an interface between the New England Control Area and an external Control Area is equal to that interface's approved capacity transfer limit (net of tie benefits, or net of HQICC in the case of the Phase I/II HVDC-TF), then the substitution auction clearing price for that interface will be determined by the demand bid or supply offer that is marginal at that interface. If a cleared demand bid associated with a Proxy De-List Bid is marginal at the external interface, then the substitution auction clearing price for that interface shall be set equal to the Capacity Clearing Price for that interface.

The substitution auction clearing price for an import-constrained Capacity Zone where the total Capacity Supply Obligations awarded in the primary action-clearing process of the Forward Capacity Auction are greater than or equal to the zone's threshold quantity specified in Section III.13.2.8.1.1 shall not be lower

than the substitution auction clearing price for the Rest-of-Pool Capacity Zone.

The substitution auction clearing price for an export-constrained Capacity Zone that is not a nested export-constrained Capacity Zone, where the total Capacity Supply Obligations awarded in the primary auction-clearing process of the Forward Capacity Auction are less than or equal to the zone's threshold quantity specified in Section III.13.2.8.1.1 shall not exceed the substitution auction clearing price for the Rest-of-Pool Capacity Zone.

The substitution auction clearing price for a nested export-constrained Capacity Zone where the total Capacity Supply Obligations awarded in the primary auction-clearing process of the Forward Capacity Auction are less than or equal to the zone's threshold quantity specified in Section III.13.2.8.1.1 shall not exceed the substitution auction clearing price for the Capacity Zone within which it is located.

The substitution auction clearing price at an external interface shall not exceed the substitution auction clearing price in the Capacity Zone connected to the external interface.

If, pursuant to the rules specified above, the substitution auction clearing price for any Capacity Zone or external interface would exceed the Capacity Clearing Price for that location, the substitution auction clearing price for that location only is set equal to its Capacity Clearing Price.

The substitution auction clearing price for any Capacity Zone or external interface cannot be less than negative one multiplied by the Forward Capacity Auction Starting Price.

III.13.2.8.2. Supply Offers in the Substitution Auction.

III.13.2.8.2.1. Supply Offers.

To participate as supply in the substitution auction, a Project Sponsor for a New Capacity Resource must meet the following criteria:

(a) The Project Sponsor and the New Capacity Resource must meet all the requirements for participation in the Forward Capacity Auction specified in Section III.13.1.

(b) The Project Sponsor must elect to have the resource participate in the substitution auction during the New Capacity Show of Interest Window. Pursuant to an election, the resource's total amount of FCA Qualified Capacity that qualifies as a New Capacity Resource will be obligated to

participate in the substitution auction, including any capacity of a Renewable Technology Resource that was not qualified due to proration pursuant to Section III.13.1.1.2.10(a), and subject to the other provisions of this Section III.13.2.8.2.

(c) The Project Sponsor must certify that the New Capacity Resource is a Sponsored Policy Resource as part of the submission of the New Capacity Qualification Package.

Substitution auction supply offers are rationable.

A resource participating in the Forward Capacity Auction as a New Generating Capacity Resource pursuant to Section III.13.1.1.1.2 (resources previously counted as capacity resources) is not eligible to participate as supply in the substitution auction. A resource is not eligible to participate as supply in the substitution auction if it has submitted a demand bid for the substitution auction.

A Composite FCM Transaction comprised of a summer resource that is a Sponsored Policy Resource is eligible to participate as supply in the substitution auction.

A Conditional Qualified New Resource may participate in the substitution auction provided that the resource with which it has overlapping interconnection impacts: (i) did not receive a Capacity Supply Obligation, fully or partially, in the primary auction-clearing process, and: (ii) is not eligible to participate in the substitution auction. A resource having a higher priority in the queue than a Conditional Qualified New Resource with which it has overlapping interconnection impact may participate in the substitution auction provided that the Conditional Qualified New Resource did not receive a Capacity Supply Obligation, fully or partially, in the primary auction-clearing process.

III.13.2.8.2.2. Supply Offer Prices.

Project Sponsors must submit substitution auction supply offer prices no later than five Business Days after the deadline for submission of offers composed of separate resources.

A substitution auction supply offer must be in the form of a curve (with up to five price-quantity pairs). The curve may not decrease in quantity as the price increases. A supply offer price for the substitution auction may not be greater than the Forward Capacity Auction Starting Price or lower than negative one multiplied by the Forward Capacity Auction Starting Price.

If the offer quantity does not equal the resource's FCA Qualified Capacity, the quantity for which no offer price was submitted will be assigned a price equal to the Forward Capacity Auction Starting Price.

III.13.2.8.2.3. Supply Offers Entered into the Substitution Auction

Supply offers for resources that satisfy all of the criteria in Section III.13.2.8.2.1 to participate in the substitution auction may be adjusted prior to conducting the substitution auction-clearing process using the following adjustments:

(a) Any portion of a resource's FCA Qualified Capacity that was cleared (received a Capacity Supply Obligation) in the primary auction-clearing process will be removed from the resource's substitution auction supply offer beginning with the lowest priced price-quantity pairs.

(b) After performing the adjustment specified in Section III.13.2.8.2.3(a), any price-quantity pairs in a resource's substitution auction supply offer with a price greater than the Capacity Clearing Price for the resource's Capacity Zone or external interface are removed from the offer.

III.13.2.8.3. Demand Bids in the Substitution Auction.

III.13.2.8.3.1. Demand Bids.

Market Participants with Existing Generating Capacity Resources or Existing Import Capacity Resources associated with External Elective Transmission Upgrades may elect to submit demand bids for the substitution auction for those resources by the Existing Capacity Retirement Deadline. The election must specify the total amount of the resource's Qualified Capacity that will be associated with its demand bid.

A resource, including any portion of an existing resource that qualifies as a New Capacity Resource, must have achieved FCM Commercial Operation no later than seven days after the issuance by the ISO of the qualification determination notification described in Section III.13.1.2.4(b) in order to participate as demand in the substitution auction.

Regardless of whether an election is made, a demand bid is required for any portion of a resource that is associated with a Retirement De-List Bid, provided that the entire resource has achieved FCM Commercial Operation no later than seven days after the issuance by the ISO of the qualification determination notification described in Section III.13.1.2.4(b).

A resource for which a demand bid election has been made cannot participate in a Composite FCM Transaction, cannot be designated as a Self-Supplied FCA Resource, and will not have incremental summer or winter capacity that does not span the entire Capacity Commitment Period subjected to the treatment specified in Section III.13.1.1.1.3.A.

Demand bids are non-rationable.

A demand bid will be entered into the substitution auction for the portion of the resource that receives a Capacity Supply Obligation in the primary auction-clearing process, subject to the other provisions of this Section III.13.2.8.3. A resource, or portion thereof, associated with a cleared demand bid shall be retired from all New England Markets at the start of the Capacity Commitment Period associated with the Forward Capacity Auction.

III.13.2.8.3.1A Substitution Auction Test Prices.

(a) **Participant-Submitted Test Price.** For auctions associated with a Capacity Commitment Period that begins on or after June 1, 2023, Market Participants that submit a substitution auction demand bid must submit a test price, calculated using the method described below, by the Existing Capacity Retirement Deadline.

The test price for the capacity associated with a resource's demand bid must be calculated using the same methodology as a Retirement De-List Bid, except that a Market Participant may not submit test prices for multiple price-quantity segments but must submit a single test price using, as necessary, aggregated cost and revenue data. The test price must be accompanied by the same documentation required for Retirement De-List Bids above the Dynamic De-List Bid Threshold pursuant to Section III.13.1.2.3.2.1. A Market Participant must submit a test price regardless of whether the price is below the Dynamic De-List Bid Threshold.

A Market Participant is not required to submit a test price for any resource for which the demand bid is less than 3 MW. The applicable test price for any such resource is $0.00/kW-month.

(b) **IMM-Determined Test Price.** The Internal Market Monitor shall review each test price submission using the methodology specified in Section III.13.1.2.3.2.1 for evaluating Retirement De-List Bids, regardless of whether the submitted test price is below the Dynamic De-List Bid Threshold. For purposes of this review, the expected revenues for a cleared substitution auction demand bid shall not be

included as a component of opportunity costs. After due consideration and consultation with the Market Participant, as appropriate, the Internal Market Monitor shall replace the submitted test price with an IMM-determined test price if the submitted test price is not consistent with the sum of the net present value of the resource's expected cash flows plus reasonable expectations about the resource's Capacity Performance Payments plus reasonable opportunity costs.

The Internal Market Monitor's determination regarding a Market Participant-submitted test price shall be included in the retirement determination notification described in Section III.13.1.2.4(a) and in the filing made to the Commission as described in Section III.13.8.1(a).

The test price used for purposes of the substitution auction shall be the Market Participant-submitted test price, as adjusted by the Internal Market Monitor pursuant to this Section III.13.2.8.3.1A(b), and as further adjusted by the Commission in response to the Internal Market Monitor's filing pursuant to Section III.13.1.2.4(a).

III.13.2.8.3.2. Demand Bid Prices.

Market Participants must submit substitution auction demand bid prices no later than five Business Days after the deadline for submission of offers composed of separate resources.

A substitution auction demand bid must be in the form of a curve (with up to five price-quantity pairs). The curve may not decrease in quantity as the price decreases. A demand bid price for the substitution auction may not be greater than the Forward Capacity Auction Starting Price or lower than negative one multiplied by the Forward Capacity Auction Starting Price.

If the bid quantity does not equal the total bid amount submitted by the Market Participant or required for a Retirement De-List Bid pursuant to Section III.13.2.8.3.1, the quantity for which no bid price was specified will be assigned a price equal to negative one multiplied by the Forward Capacity Auction Starting Price.

For auctions associated with a Capacity Commitment Period that begins on or after June 1, 2023, Market Participants may elect either of the demand bid adjustment methods specified in Section III.13.2.8.3.3(b) for the resource by no later than five Business Days after the deadline for submission of offers composed of separate resources. If no such election is made, the adjustment applied shall be the method specified in Section III.13.2.8.3.3(b)(i).

III.13.2.8.3.3. Demand Bids Entered into the Substitution Auction.

If a resource is determined to be needed for reliability pursuant to Section III.13.2.5.2.5, then any demand bid associated with the resource will not be further included in the substitution auction. If a resource is awarded a Capacity Supply Obligation in the primary auction-clearing process and the Capacity Clearing Price is less than ninety percent of the resource's test price as established pursuant to Section III.13.2.8.3.1A, then the resource's demand bid will not be included in the substitution auction.

Demand bids for resources that satisfy all of the criteria in Section III.13.2.8.3.1 to participate in the substitution auction will be adjusted prior to conducting the substitution auction-clearing process using the following adjustments:

(a) For the substitution auction associated with the Capacity Commitment Period beginning on June 1, 2022, any portion of a resource's demand bid that exceeds its Capacity Supply Obligation awarded in the primary auction-clearing process will be removed from the substitution auction demand bid beginning with the highest priced price-quantity pairs.

(b) For substitution auctions associated with a Capacity Commitment Period that begins on or after June 1, 2023, a resource's demand bid will be adjusted using one of the following methods as elected pursuant to Section III.13.2.8.3.2:

(i) The portion of a resource's capacity that did not receive a Capacity Supply Obligation in the primary auction-clearing process will be removed from the substitution auction demand bid beginning with the highest priced price-quantity pair.

(ii) Any portion of a resource's demand bid that exceeds its Capacity Supply Obligation awarded in the primary auction-clearing process will be removed from the substitution auction demand bid beginning with the lowest priced price-quantity pair.

(c) After performing the modification specified in Sections III.13.2.8.3.3(a) or III.13.2.8.3.3(b), any price-quantity pairs in a resource's substitution auction demand bid with a price greater than the Capacity Clearing Price for the resource's Capacity Zone or external interface will have its price reduced to the Capacity Clearing Price for the resource's Capacity Zone or external interface.

Except as provided in Section III.13.2.5.2.1(c), a rationable demand bid will be entered into the substitution auction on behalf of any Proxy De-List Bid associated with a Permanent De-List Bid or

Retirement De-List Bid. The demand bid quantity will equal the portion of the Proxy De-List Bid that was not cleared (received a Capacity Supply Obligation) in the first run of the primary auction-clearing process. The demand bid will have priority to clear before non-rationable demand bids.

SECTION III

MARKET RULE 1

APPENDIX A

MARKET MONITORING,
REPORTING AND MARKET POWER MITIGATION

APPENDIX A

MARKET MONITORING, REPORTING AND MARKET POWER MITIGATION

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MARKET MONITORING, REPORTING AND MARKET POWER MITIGATION

III.A.1. Introduction and Purpose; Structure and Oversight: Independence.

III.A.1.1. Mission Statement.

The mission of the Internal Market Monitor and External Market Monitor shall be (1) to protect both consumers and Market Participants by the identification and reporting of market design flaws and market power abuses; (2) to evaluate existing and proposed market rules, tariff provisions and market design elements to remove or prevent market design flaws and recommend proposed rule and tariff changes to the ISO; (3) to review and report on the performance of the New England Markets; (4) to identify and notify the Commission of instances in which a Market Participant's behavior, or that of the ISO, may require investigation; and (5) to carry out the mitigation functions set forth in this ***Appendix A.***

III.A.1.2. Structure and Oversight.

The market monitoring and mitigation functions contained in this ***Appendix A*** shall be performed by the Internal Market Monitor, which shall report to the ISO Board of Directors and, for administrative purposes only, to the ISO Chief Executive Officer, and by an External Market Monitor selected by and reporting to the ISO Board of Directors. Members of the ISO Board of Directors who also perform management functions for the ISO shall be excluded from oversight and governance of the Internal Market Monitor and External Market Monitor. The ISO shall enter into a contract with the External Market Monitor addressing the roles and responsibilities of the External Market Monitor as detailed in this ***Appendix A***. The ISO shall file its contract with the External Market Monitor with the Commission. In order to facilitate the performance of the External Market Monitor's functions, the External Market Monitor shall have, and the ISO's contract with the External Market Monitor shall provide for, access by the External Market Monitor to ISO data and personnel, including ISO management responsible for market monitoring, operations and billing and settlement functions. Any proposed termination of the contract with the External Market Monitor or modification of, or other limitation on, the External Market Monitor's scope of work shall be subject to prior Commission approval.

III.A.1.3. Data Access and Information Sharing.

The ISO shall provide the Internal Market Monitor and External Market Monitor with access to all market data, resources and personnel sufficient to enable the Internal Market Monitor and External Market Monitor to perform the market monitoring and mitigation functions provided for in this ***Appendix A***.

This access shall include access to any confidential market information that the ISO receives from another independent system operator or regional transmission organization subject to the Commission's jurisdiction, or its market monitor, as part of an investigation to determine (a) if a Market Violation is occurring or has occurred, (b) if market power is being or has been exercised, or (c) if a market design flaw exists. In addition, the Internal Market Monitor and External Market Monitor shall have full access to the ISO's electronically generated information and databases and shall have exclusive control over any data created by the Internal Market Monitor or External Market Monitor. The Internal Market Monitor and External Market Monitor may share any data created by it with the ISO, which shall maintain the confidentiality of such data in accordance with the terms of the ISO New England Information Policy.

III.A.1.4. Interpretation.

In the event that any provision of any ISO New England Filed Document is inconsistent with the provisions of this ***Appendix A***, the provisions of ***Appendix A*** shall control. Notwithstanding the foregoing, Sections III.A.1.2, III.A.2.2 (a)-(c), (e)-(h), Section III.A.2.3 (a)-(g), (i), (n) and Section III.A.17.3 are also part of the Participants Agreement and cannot be modified in either ***Appendix A*** or the Participants Agreement without a corresponding modification at the same time to the same language in the other document.

III.A.1.5. Definitions.

Capitalized terms not defined in this ***Appendix A*** are defined in the definitions section of Section I of the Tariff.

III.A.2. Functions of the Market Monitor.

III.A.2.1. Core Functions of the Internal Market Monitor and External Market Monitor.

The Internal Market Monitor and External Market Monitor will perform the following core functions:

(a) Evaluate existing and proposed market rules, tariff provisions and market design elements, and recommend proposed rule and tariff changes to the ISO, the Commission, Market Participants, public utility commissioners of the six New England states, and to other interested entities, with the understanding that the Internal Market Monitor and External Market Monitor are not to effectuate any proposed market designs (except as specifically provided in Section III.A.2.4.4, Section III.A.9 and Section III.A.10 of this ***Appendix A***). In the event the Internal Market Monitor or External Market Monitor believes broader dissemination could lead to exploitation, it shall limit distribution of its

identifications and recommendations to the ISO and to the Commission, with an explanation of why broader dissemination should be avoided at that time. Nothing in this Section III.A.2.1 (a) shall prohibit or restrict the Internal Market Monitor and External Market Monitor from implementing Commission accepted rule and tariff provisions regarding market monitoring or mitigation functions that, according to the terms of the applicable rule or tariff language, are to be performed by the Internal Market Monitor or External Market Monitor.

(b) Review and report on the performance of the New England Markets to the ISO, the Commission, Market Participants, the public utility commissioners of the six New England states, and to other interested entities.

(c) Identify and notify the Commission's Office of Enforcement of instances in which a Market Participant's behavior, or that of the ISO, may require investigation, including suspected tariff violations, suspected violations of Commission-approved rules and regulations, suspected market manipulation, and inappropriate dispatch that creates substantial concerns regarding unnecessary market inefficiencies.

III.A.2.2. Functions of the External Market Monitor.

To accomplish the functions specified in Section III.A.2.1 of this ***Appendix A***, the External Market Monitor shall perform the following functions:

(a) Review the competitiveness of the New England Markets, the impact that the market rules and/or changes to the market rules will have on the New England Markets and the impact that the ISO's actions have had on the New England Markets. In the event that the External Market Monitor uncovers problems with the New England Markets, the External Market Monitor shall promptly inform the Commission, the Commission's Office of Energy Market Regulation staff, the ISO Board of Directors, the public utility commissions for each of the six New England states, and the Market Participants of its findings in accordance with the procedures outlined in Sections III.A.19 and III.A.20 of this ***Appendix A***, provided that in the case of Market Participants and the public utility commissions, information in such findings shall be redacted as necessary to comply with the ISO New England Information Policy. Notwithstanding the foregoing, in the event the External Market Monitor believes broader dissemination could lead to exploitation, it shall limit distribution of its identifications to the ISO and to the Commission, with an explanation of why broader dissemination should be avoided at that time.

(b) Perform independent evaluations and prepare annual and ad hoc reports on the overall competitiveness and efficiency of the New England Markets or particular aspects of the New England

Markets, including the adequacy of this ***Appendix A***, in accordance with the provisions of Section III.A.17 of this ***Appendix A***.

(c) Conduct evaluations and prepare reports on its own initiative or at the request of others.

(d) Monitor and review the quality and appropriateness of the mitigation conducted by the Internal Market Monitor. In the event that the External Market Monitor discovers problems with the quality or appropriateness of such mitigation, the External Market Monitor shall promptly inform the Commission, the Commission's Office of Energy Market Regulation staff, the ISO Board of Directors, the public utility commissions for each of the six New England states, and the Market Participants of its findings in accordance with the procedures outlined in Sections III.A.19 and/or III.A.20 of this ***Appendix A,*** provided that in the case of Market Participants and the public utility commissions, information in such findings shall be redacted as necessary to comply with the ISO New England Information Policy. Notwithstanding the foregoing, in the event the External Market Monitor believes broader dissemination could lead to exploitation, it shall limit distribution of its identifications to the ISO and to the Commission, with an explanation of why broader dissemination should be avoided at that time.

(e) Prepare recommendations to the ISO Board of Directors and the Market Participants on how to improve the overall competitiveness and efficiency of the New England Markets or particular aspects of the New England Markets, including improvements to this ***Appendix A***.

(f) Recommend actions to the ISO Board of Directors and the Market Participants to increase liquidity and efficient trade between regions and improve the efficiency of the New England Markets.

(g) Review the ISO's filings with the Commission from the standpoint of the effects of any such filing on the competitiveness and efficiency of the New England Markets. The External Market Monitor will have the opportunity to comment on any filings under development by the ISO and may file comments with the Commission when the filings are made by the ISO. The subject of any such comments will be the External Market Monitor's assessment of the effects of any proposed filing on the competitiveness and efficiency of the New England Markets, or the effectiveness of this ***Appendix A***, as appropriate.

(h) Provide information to be directly included in the monthly market updates that are provided at the meetings of the Market Participants.

III.A.2.3. Functions of the Internal Market Monitor.

To accomplish the functions specified in Section III.A.2.1 of this ***Appendix A***, the Internal Market Monitor shall perform the following functions:

(a) Maintain ***Appendix A*** and consider whether ***Appendix A*** requires amendment. Any amendments deemed to be necessary by the Internal Market Monitor shall be undertaken after consultation with Market Participants in accordance with Section 11 of the Participants Agreement.

(b) Perform the day-to-day, real-time review of market behavior in accordance with the provisions of this ***Appendix A***.

(c) Consult with the External Market Monitor, as needed, with respect to implementing and applying the provisions of this ***Appendix A.***

(d) Identify and notify the Commission's Office of Enforcement staff of instances in which a Market Participant's behavior, or that of the ISO, may require investigation, including suspected Tariff violations, suspected violations of Commission-approved rules and regulations, suspected market manipulation, and inappropriate dispatch that creates substantial concerns regarding unnecessary market inefficiencies, in accordance with the procedures outlined in Section III.A.19 of this ***Appendix A.***

(e) Review the competitiveness of the New England Markets, the impact that the market rules and/or changes to the market rules will have on the New England Markets and the impact that ISO's actions have had on the New England Markets. In the event that the Internal Market Monitor uncovers problems with the New England Markets, the Internal Market Monitor shall promptly inform the Commission, the Commission's Office of Energy Market Regulation staff, the ISO Board of Directors, the public utility commissions for each of the six New England states, and the Market Participants of its findings in accordance with the procedures outlined in Sections III.A.19 and III.A.20 of this ***Appendix A***, provided that in the case of Market Participants and the public utility commissions, information in such findings shall be redacted as necessary to comply with the ISO New England Information Policy. Notwithstanding the foregoing, in the event the Internal Market Monitor believes broader dissemination could lead to exploitation, it shall limit distribution of its identifications to the ISO and to the Commission, with an explanation of why broader dissemination should be avoided at that time.

(f) Provide support and information to the ISO Board of Directors and the External Market Monitor consistent with the Internal Market Monitor's functions.

(g) Prepare an annual state of the market report on market trends and the performance of the New England Markets, as well as less extensive quarterly reports, in accordance with the provisions of Section III.A.17 of this ***Appendix A***.

(h) Make one or more of the Internal Market Monitor staff members available for regular conference calls, which may be attended, telephonically or in person, by Commission and state commission staff, by representatives of the ISO, and by Market Participants. The information to be provided in the

Internal Market Monitor conference calls is generally to consist of a review of market data and analyses of the type regularly gathered and prepared by the Internal Market Monitor in the course of its business, subject to appropriate confidentiality restrictions. This function may be performed through making a staff member of the Internal Market Monitor available for the monthly meetings of the Market Participants and inviting Commission staff and the staff of state public utility commissions to those monthly meetings.

(i) Be primarily responsible for interaction with external Control Areas, the Commission, other regulators and Market Participants with respect to the matters addressed in this ***Appendix A***.

(j) Monitor for conduct whether by a single Market Participant or by multiple Market Participants acting in concert, including actions involving more than one Resource, that may cause a material effect on prices or other payments in the New England Markets if exercised from a position of market power, and impose appropriate mitigation measures if such conduct is detected and the other applicable conditions for the imposition of mitigation measures as set forth in this ***Appendix A*** are met. The categories of conduct for which the Internal Market Monitor shall perform monitoring for potential mitigation are:

(i) *Economic withholding*, that is, submitting a Supply Offer for a Resource that is unjustifiably high and violates the economic withholding criteria set forth in Section III.A.5 so that (i) the Resource is not or will not be dispatched or scheduled, or (ii) the bid or offer will set an unjustifiably high market clearing price.

(ii) *Uneconomic production from a Resource*, that is, increasing the output of a Resource to levels that would otherwise be uneconomic, absent an order of the ISO, in order to cause, and obtain benefits from, a transmission constraint.

(iii) *Anti-competitive Increment Offers and Decrement Bids*, which are bidding practices relating to Increment Offers and Decrement Bids that cause Day-Ahead LMPs not to achieve the degree of convergence with Real-Time LMPs that would be expected in a workably competitive market, more fully addressed in Section III.A.11 of this ***Appendix A***.

(iv) *Anti-competitive Demand Bids*, which are addressed in Section III.A.10 of this ***Appendix A.***

(v) Other categories of conduct that have material effects on prices or NCPC payments in the New England Markets. The Internal Market Monitor, in consultation with the External Market Monitor, shall; (i) seek to amend ***Appendix A*** as may be appropriate to include any such conduct that would substantially distort or impair the competitiveness of any of

the New England Markets; and (ii) seek such other authorization to mitigate the effects of such conduct from the Commission as may be appropriate.

(k) Perform such additional monitoring as the Internal Market Monitor deems necessary, including without limitation, monitoring for:

(i) Anti-competitive gaming of Resources;
(ii) Conduct and market outcomes that are inconsistent with competitive markets;
(iii) Flaws in market design or software or in the implementation of rules by the ISO that create inefficient incentives or market outcomes;
(iv) Actions in one market that affect price in another market;
(v) Other aspects of market implementation that prevent competitive market results, the extent to which market rules, including this ***Appendix A***, interfere with efficient market operation, both short-run and long-run; and
(vi) Rules or conduct that creates barriers to entry into a market.

The Internal Market Monitor will include significant results of such monitoring in its reports under Section III.A.17 of this ***Appendix A***. Monitoring under this Section III.A.2.3(k) cannot serve as a basis for mitigation under III.A.11 of this ***Appendix A.*** If the Internal Market Monitor concludes as a result of its monitoring that additional specific monitoring thresholds or mitigation remedies are necessary, it may proceed under Section III.A.20.

(l) Propose to the ISO and Market Participants appropriate mitigation measures or market rule changes for conduct that departs significantly from the conduct that would be expected under competitive market conditions but does not rise to the thresholds specified in Sections III.A.5, III.A.10, or III.A.11. In considering whether to recommend such changes, the Internal Market Monitor shall evaluate whether the conduct has a significant effect on market prices or NCPC payments as specified below. The Internal Market Monitor will not recommend changes if it determines, from information provided by Market Participants (or parties that would be subject to mitigation) or from other information available to the Internal Market Monitor, that the conduct and associated price or NCPC payments under investigation are attributable to legitimate competitive market forces or incentives.

(m) Evaluate physical withholding of Supply Offers in accordance with Section III.A.4 below for referral to the Commission in accordance with ***Appendix B*** of this Market Rule l.

(n) If and when established, participate in a committee of regional market monitors to review issues associated with interregional transactions, including any barriers to efficient trade and competition.

III.A.2.4. Overview of the Internal Market Monitor's Mitigation Functions.

III.A.2.4.1. Purpose.

The mitigation measures set forth in this ***Appendix A*** for mitigation of market power are intended to provide the means for the Internal Market Monitor to mitigate the market effects of any actions or transactions that are without a legitimate business purpose and that are intended to or foreseeably could manipulate market prices, market conditions, or market rules for electric energy or electricity products. Actions or transactions undertaken by a Market Participant that are explicitly contemplated in Market Rule l (such as virtual supply or load bidding) or taken at the direction of the ISO are not in violation of this ***Appendix A***. These mitigation measures are intended to minimize interference with open and competitive markets, and thus to permit to the maximum extent practicable, price levels to be determined by competitive forces under the prevailing market conditions. To that end, the mitigation measures authorize the mitigation of only specific conduct that exceeds well-defined thresholds specified below. When implemented, mitigation measures affecting the LMP or clearing prices in other markets will be applied *ex ante*. Nothing in this ***Appendix A***, including the application of a mitigation measure, shall be deemed to be a limitation of the ISO's authority to evaluate Market Participant behavior for potential sanctions under ***Appendix B*** of this Market Rule 1.

III.A.2.4.2. Conditions for the Imposition of Mitigation.

(a) Imposing Mitigation. To achieve the foregoing purpose and objectives, mitigation measures are imposed pursuant to Sections III.A.5, III.A.10, and III.A.11 below:

(b) Notwithstanding the foregoing or any other provision of this ***Appendix A***, and as more fully described in Section III.B.3.2.6 of ***Appendix B*** to this Market Rule 1, certain economic decisions shall not be deemed a form of withholding or otherwise inconsistent with competitive conduct.

III.A.2.4.3. Applicability.

Mitigation measures may be applied to Supply Offers, Increment Offers, Demand Bids, and Decrement Bids, as well as to the scheduling or operation of a generation unit or transmission facility.

III.A.2.4.4. Mitigation Not Provided for Under This *Appendix A*.

The Internal Market Monitor shall monitor the New England Markets for conduct that it determines constitutes an abuse of market power but does not trigger the thresholds specified below for the imposition of mitigation measures by the Internal Market Monitor. If the Internal Market Monitor identifies any such conduct, and in particular conduct exceeding the thresholds specified in this ***Appendix A***, it may make a filing under §205 of the Federal Power Act ("§205") with the Commission requesting authorization to apply appropriate mitigation measures. Any such filing shall identify the particular conduct the Internal Market Monitor believes warrants mitigation, shall propose a specific mitigation measure for the conduct, and shall set forth the Internal Market Monitor's justification for imposing that mitigation measure.

III.A.2.4.5. Duration of Mitigation.

Any mitigation measure imposed on a specific Market Participant, as specified below, shall expire not later than six months after the occurrence of the conduct giving rise to the measure, or at such earlier time as may be specified by the Internal Market Monitor or as otherwise provided in this ***Appendix A*** or in ***Appendix B*** to this Market Rule 1.

III.A.3. Consultation Prior to Determination of Reference Levels for Physical and Financial Parameters of Resources; Fuel Price Adjustments.

Upon request of a Market Participant or at the initiative of the Internal Market Monitor, the Internal Market Monitor shall consult with a Market Participant with respect to the information and analysis used to determine Reference Levels under Section III.A.7 for that Market Participant**.** In order for the Internal Market Monitor to revise Reference Levels or treat an offer as not violating applicable conduct tests specified in Section III.A.5.5 for an Operating Day for which the offer is submitted, all cost data and other information, other than automated index-based cost data received by the Internal Market Monitor from third party vendors, cost data and information calculated by the Internal Market Monitor, and cost data and information provided under the provisions of Section III.A.3.1 or Section III.A.3.2, must be submitted by a Market Participant, and all consultations must be completed, no later than 5:00 p.m. of the second business day prior to the Operating Day for which the Reference Level will be effective. Adjustments to fuel prices after this time must be submitted in accordance with the fuel price adjustment provisions in Section III.A.3.4.

III.A.3.1. Consultation Prior to Offer.

If an event occurs within the 24 hour period prior to the Operating Day that a Market Participant, including a Market Participant that is not permitted to submit a fuel price adjustment pursuant to Section III.A.3.4(d) believes will cause the operating cost of a Resource to exceed the level that would violate one of the conduct tests specified in Section III.A.5 of this ***Appendix A***, the Market Participant may contact the Internal Market Monitor to provide an explanation of the increased costs. In order for the information to be considered for the purposes of the Day-Ahead Energy Market, the Market Participant must contact the Internal Market Monitor at least 30 minutes prior to the close of the Day-Ahead Energy Market. In order for the information to be considered for purposes of the first commitment analysis performed following the close of the Re-Offer Period, the Market Participant must contact the Internal Market Monitor at least 30 minutes prior to the close of the Re-Offer Period. Cost information submitted thereafter shall be considered in subsequent commitment and dispatch analyses if received between 8:00 a.m. and 5:00 p.m. and at least one hour prior to the close of the next hourly Supply Offer submittal period. If the Internal Market Monitor determines that there is an increased cost, the Internal Market Monitor will either update the Reference Level or treat an offer as not violating applicable conduct tests specified in Section III.A.5.5 for the Operating Day for which the offer is submitted. Any request and all supporting cost data and other verifiable supporting information must be submitted to the Internal Market Monitor prior to the Market participant's submission of the offer.

If a Market Participant believes that the fuel price determined under Section III.A.7.5(e) should be modified, it may contact the Internal Market Monitor to request a change to the fuel price and provide an explanation of the basis for the change. Any request to change the fuel price determined under Section III.A.7.5(e) must be received between the hours of 8:00 a.m. and 5:00 p.m. on any day.

III.A.3.2. Dual Fuel Resources.

In evaluating bids or offers under this ***Appendix A*** for dual fuel Resources, the Internal Market Monitor shall utilize the fuel type specified in the Supply Offer for the calculation of Reference Levels pursuant to Section III.A.7 below. If a Market Participant specifies a fuel type in the Supply Offer that, at the time the Supply Offer is submitted, is the higher cost fuel available to the Resource, then if the ratio of the higher cost fuel to the lower cost fuel, as calculated in accordance with the formula specified below, is greater than 1.75, the Market Participant must within five Business Days:

(a) provide the Internal Market Monitor with written verification as to the cause for the use of the higher cost fuel.

(b) provide the Internal Market Monitor with evidence that the higher cost fuel was used.

If the Market Participant fails to provide supporting information demonstrating the use of the higher-cost fuel within five Business Days of the Operating Day, then the Reference Level based on the lower cost fuel will be used in place of the Supply Offer for settlement purposes.

For purposes of this Section III.A.3.2, the ratio of the Resource's higher cost fuel to the lower cost fuel is calculated as, for the two primary fuels utilized in the dispatch of the Resource, the maximum fuel index price for the Operating Day divided by the minimum fuel index price for the Operating Day, using the two fuel indices that are utilized in the calculation of the Resource's Reference Levels for the Day-Ahead Energy Market for that Operating Day.

III.A.3.3. Market Participant Access to its Reference Levels.

The Internal Market Monitor will make available to the Market Participant the Reference Levels applicable to that Market Participant's Supply Offers through the MUI. Updated Reference Levels will be made available whenever calculated. The Market Participant shall not modify such Reference Levels in the ISO's or Internal Market Monitor's systems.

III.A.3.4. Fuel Price Adjustments.

(a) A Market Participant may submit a fuel price, to be used in calculating the Reference Levels for a Resource's Supply Offer, whenever the Market Participant's expected price to procure fuel for the Resource will be greater than that used by the Internal Market Monitor in calculating the Reference Levels for the Supply Offer. A fuel price may be submitted for Supply Offers entered in the Day-Ahead Energy Market, the Re-Offer Period, or for a Real-Time Offer Change. A fuel price is subject to the following conditions:

(i) In order for the submitted fuel price to be utilized in calculating the Reference Levels for a Supply Offer, the fuel price must be submitted prior to the applicable Supply Offer deadline,

(ii) The submitted fuel price must reflect the price at which the Market Participant expects to be able to procure fuel to supply energy under the terms of its Supply Offer, exclusive of resource-specific transportation costs. Modifications to Reference Levels based on changes to transportation costs must be addressed through the consultation process specified in Section III.A.3.1.

(iii) The submitted fuel price may be no lower than the lesser of (1) 110% of the fuel price used by the Internal Market Monitor in calculating the Reference Levels for the Resource's Supply Offer

or (2) the fuel price used by the Internal Market Monitor in calculating the Reference Levels for the Resource's Supply Offer plus $2.50/MMbtu.

(b) Within five Business Days following submittal of a fuel price, a Market Participant must provide the Internal Market Monitor with documentation or analysis to support the submitted fuel price, which may include but is not limited to (i) an invoice or purchase confirmation for the fuel utilized or (ii) a quote from a named supplier or (iii) a price from a publicly available trading platform or price reporting agency, demonstrating that the submitted fuel price reflects the cost at which the Market Participant expected to purchase fuel for the operating period covered by the Supply Offer, as of the time that the Supply Offer was submitted, under an arm's length fuel purchase transaction. Any amount to be added to the quote from a named supplier, or to a price from a publicly available trading platform or price reporting agency, must be submitted and approved using the provision for consultations prior to the determination of Reference Levels in Section III.A.3. The submitted fuel price must be consistent with the fuel price reflected on the submitted invoice or purchase confirmation for the fuel utilized, the quote from a named supplier or the price from a publicly available trading platform or price reporting agency, plus any approved adder, or the other documentation or analysis provided to support the submitted fuel price.

(c) If, within a 12 month period, the requirements in sub-section (b) are not met for a Resource and, for the time period for which the fuel price adjustment that does not meet the requirements in sub-section (b) was submitted, (i) the Market Participant was determined to be pivotal according to the pivotal supplier test described in Section III.A.5.2.1or (ii) the Resource was determined to be in a constrained area according to the constrained area test described in Section III.A.5.2.2 or (iii) the Resource satisfied any of the conditions described in Section III.A.5.5.6.1, then a fuel price adjustment pursuant to Section III.A.3.4 shall not be permitted for that Resource for up to six months. The following table specifies the number of months for which a Market Participant will be precluded from using the fuel price adjustment, based on the number of times the requirements in sub-section (b) are not met within the 12 month period. The 12 month period excludes any previous days for which the Market Participant was precluded from using the fuel price adjustment. The period of time for which a Market Participant is precluded from using the fuel price adjustment begins two weeks after the most-recent incident occurs.

Number of Incidents	Months Precluded (starting from most-recent incident)
1	2

2 or more	6

III.A.4. Physical Withholding.

III.A.4.1. Identification of Conduct Inconsistent with Competition.

This section defines thresholds used to identify possible instances of physical withholding. This section does not limit the Internal Market Monitor's ability to refer potential instances of physical withholding to the Commission.

Generally, physical withholding involves not offering to sell or schedule the output of or services provided by a Resource capable of serving the New England Markets when it is economic to do so. Physical withholding may include, but is not limited to:

(a) falsely declaring that a Resource has been forced out of service or otherwise become unavailable,

(b) refusing to make a Supply Offer, or schedules for a Resource when it would be in the economic interest absent market power, of the withholding entity to do so,

(c) operating a Resource in Real-Time to produce an output level that is less than the ISO Dispatch Rate, or

(d) operating a transmission facility in a manner that is not economic, is not justified on the basis of legitimate safety or reliability concerns, and contributes to a binding transmission constraint.

III.A.4.2. Thresholds for Identifying Physical Withholding.

III.A.4.2.1. Initial Thresholds.

Except as specified in subsection III.A.4.2.4 below, the following initial thresholds will be employed by the Internal Market Monitor to identify physical withholding of a Resource:

(a) Withholding that exceeds the lower of 10% or 100 MW of a Resource's capacity;

(b) Withholding that exceeds in the aggregate the lower of 5% or 200 MW of a Market Participant's total capacity for Market Participants with more than one Resource; or

(c) Operating a Resource in Real-Time at an output level that is less than 90% of the ISO's Dispatch Rate for the Resource.

III.A.4.2.2. Adjustment to Generating Capacity.

The amounts of generating capacity considered withheld for purposes of applying the foregoing thresholds shall include unjustified deratings, that is, falsely declaring a Resource derated, and the portions of a Resource's available output that are not offered. The amounts deemed withheld shall not include generating output that is subject to a forced outage or capacity that is out of service for maintenance in accordance with an ISO maintenance schedule, subject to verification by the Internal Market Monitor as may be appropriate that an outage was forced.

III.A.4.2.3. Withholding of Transmission.

A transmission facility shall be deemed physically withheld if it is not operated in accordance with ISO instructions and such failure to conform to ISO instructions causes transmission congestion. A transmission facility shall not be deemed withheld if it is subject to a forced outage or is out of service for maintenance in accordance with an ISO maintenance schedule, subject to verification by the Internal Market Monitor as may be appropriate that an outage was forced.

III.A.4.2.4. Resources in Congestion Areas.

Minimum quantity thresholds shall not be applicable to the identification of physical withholding by a Resource in an area the ISO has determined is congested.

III.A.4.3. Hourly Market Impacts.

Before evaluating possible instances of physical withholding for imposition of sanctions, the Internal Market Monitor shall investigate the reasons for the change in accordance with Section III.A.3. If the physical withholding in question is not explained to the satisfaction of the Internal Market Monitor, the Internal Market Monitor will determine whether the conduct in question causes a price impact in the New England Markets in excess of any of the thresholds specified in Section III.A.5, as appropriate.

III.A.5. Mitigation.

III.A.5.1. Resources with Capacity Supply Obligations.

Only Supply Offers associated with Resources with Capacity Supply Obligations will be evaluated for economic withholding in the Day-Ahead Energy Market. All Supply Offers will be evaluated for economic withholding in the Real-Time Energy Market.

III.A.5.1.1. Resources with Partial Capacity Supply Obligations.

Supply Offers associated with Resources with a Capacity Supply Obligation for less than their full capacity shall be evaluated for economic withholding and mitigation as follows:

(a) all Supply Offer parameters shall be reviewed for economic withholding;

(b) the energy price Supply Offer parameter shall be reviewed for economic withholding up to and including the higher of: (i) the block containing the Resource's Economic Minimum Limit, or; (ii) the highest block that includes any portion of the Capacity Supply Obligation;

(c) if a Resource with a partial Capacity Supply Obligation consists of multiple assets, the offer blocks associated with the Resource that shall be evaluated for mitigation shall be determined by using each asset's Seasonal Claimed Capability value in proportion to the total of the Seasonal Claimed Capabilities for all of the assets that make up the Resource. The Lead Market Participant of a Resource with a partial Capacity Supply Obligation consisting of multiple assets may also propose to the Internal Market Monitor the offer blocks that shall be evaluated for mitigation based on an alternative allocation on a monthly basis. The proposal must be made at least five Business Days prior to the start of the month. A proposal shall be rejected by the Internal Market Monitor if the designation would be inconsistent with competitive behavior

III.A.5.2. Structural Tests.

There are two structural tests that determine which mitigation thresholds are applied to a Supply Offer:

(a) if a supplier is determined to be pivotal according to the pivotal supplier test, then the thresholds in Section III.A.5.5.1 "General Threshold Energy Mitigation" and Section III.A.5.5.4 "General Threshold Commitment Mitigation" apply, and;

(b) if a Resource is determined to be in a constrained area according to the constrained area test, then the thresholds in Section III.A.5.5.2 "Constrained Area Energy Mitigation" and Section III.A.5.5.4 "Constrained Area Commitment Mitigation" apply.

III.A.5.2.1. Pivotal Supplier Test.

The pivotal supplier test examines whether a Market Participant has aggregate energy Supply Offers (up to and including Economic Max) that exceed the supply margin in the Real-Time Energy Market. A Market Participant whose aggregate energy associated with Supply Offers exceeds the supply margin is a pivotal supplier.

The supply margin for an interval is the total energy Supply Offers from available Resources (up to and including Economic Max), less total system load (as adjusted for net interchange with other Control Areas, including Operating Reserve). Resources are considered available for an interval if they can provide energy within the interval. The applicable interval for the current operating plan in the Real-Time Energy Market is any of the hours in the plan. The applicable interval for UDS is the interval for which UDS issues instructions.

The pivotal supplier test shall be run prior to each determination of a new operating plan for the Operating Day, and prior to each execution of the UDS.

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III.A.5.2.2. Constrained Area Test.

A Resource is considered to be within a constrained area if:

(a) for purposes of the Real-Time Energy Market, the Resource is located on the import-constrained side of a binding constraint and there is a sensitivity to the binding constraint such that the UDS used to relieve transmission constraints would commit or dispatch the Resource in order to relieve that binding transmission constraint, or;

(b) for purposes of the Day-Ahead Energy Market, the LMP at the Resource's Node exceeds the LMP at the Hub by more than $25/MWh.

III.A.5.3. Calculation of Impact Test in the Day-Ahead Energy Market.

The price impact for the purposes of Section III.A.5.5.2 "Constrained Area Energy Mitigation" is equal to the difference between the LMP at the Resource's Node and the LMP at the Hub.

III.A.5.4. Calculation of Impact Tests in the Real-Time Energy Market.

The energy price impact test applied in the Real-Time Energy Market shall compare two LMPs at the Resource's Node. The first LMP will be calculated based on the Supply Offers submitted for all Resources. If a Supply Offer has been mitigated in a prior interval, the calculation of the first LMP shall be based on the mitigated value. The second LMP shall be calculated substituting Reference Levels for

Supply Offers that have failed the applicable conduct test. The difference between the two LMPs is the price impact of the conduct violation.

A Supply Offer shall be determined to have no price impact if the offer block that violates the conduct test is:

(a) less than the LMP calculated using the submitted Supply Offers, and less than the LMP calculated using Reference Levels for Supply Offers that have failed the conduct test, or;
(b) greater than the LMP calculated using the submitted Supply Offers, and greater than the LMP calculated using Reference Levels for Supply Offers that have failed the conduct test, and the Resource has not been dispatched into the offer block that exceeds the LMP.

III.A.5.5. Mitigation by Type.

III.A.5.5.1. General Threshold Energy Mitigation.

III.A.5.5.1.1. Applicability.

Mitigation pursuant to this section shall be applied to all Supply Offers in the Real-Time Energy Market submitted by a Lead Market Participant that is determined to be a pivotal supplier in the Real-Time Energy Market.

III.A.5.5.1.2. Conduct Test.

A Supply Offer fails the conduct test for general threshold energy mitigation if any offer block price exceeds the Reference Level by an amount greater than 300% or $100/MWh, whichever is lower. Offer block prices below $25/MWh are not subject to the conduct test.

III.A.5.5.1.3. Impact Test.

A Supply Offer that fails the conduct test for general threshold energy mitigation shall be evaluated against the impact test for general threshold energy mitigation. A Supply Offer fails the impact test for general threshold energy mitigation if there is an increase in the LMP greater than 200% or $100/MWh, whichever is lower as determined by the real-time impact test.

III.A.5.5.1.4. Consequence of Failing Both Conduct and Impact Test.

If a Supply Offer fails the general threshold conduct and impact tests, then the financial parameters of the Supply Offer shall be set to their Reference Levels, including all energy offer block prices and all types of Start-Up Fees and the No-Load Fee.

III.A.5.5.2. Constrained Area Energy Mitigation.

III.A.5.5.2.1. Applicability.

Mitigation pursuant to this section shall be applied to Supply Offers in the Day-Ahead Energy Market and Real-Time Energy Market associated with a Resource determined to be within a constrained area.

III.A.5.5.2.2. Conduct Test.

A Supply Offer fails the conduct test for constrained area energy mitigation if any offer block price exceeds the Reference Level by an amount greater than 50% or $25/MWh, whichever is lower.

III.A.5.5.2.3. Impact Test.

A Supply Offer fails the impact test for constrained area energy mitigation if there is an increase greater than 50% or $25/MWh, whichever is lower, in the LMP as determined by the day-ahead or real-time impact test.

III.A.5.5.2.4. Consequence of Failing Both Conduct and Impact Test.

If a Supply Offer fails the constrained area conduct and impact tests, then the financial parameters of the Supply Offer shall be set to their Reference Levels, including all energy offer blocks and all types of Start-Up Fees and the No-Load Fee.

III.A.5.5.3. Manual Dispatch Energy Mitigation.

III.A.5.5.3.1. Applicability.

Mitigation pursuant to this section shall be applied to Supply Offers associated with a Resource, when the Resource is manually dispatched above the Economic Minimum Limit value specified in the Resource's Supply Offer and the energy price parameter of its Supply Offer at the Desired Dispatch Point is greater than the Real-Time Price at the Resource's Node.

III.A.5.5.3.2. Conduct Test.

A Supply Offer fails the conduct test for manual dispatch energy mitigation if any offer block price divided by the Reference Level is greater than 1.10.

III.A.5.5.3.3. Consequence of Failing the Conduct Test.

If a Supply Offer for a Resource fails the manual dispatch energy conduct test, then the financial parameters of the Supply Offer shall be set to their Reference Levels, including all energy offer blocks and all types of Start-Up Fees and the No-Load Fee.

III.A.5.5.4. General Threshold Commitment Mitigation.

III.A.5.5.4.1. Applicability.

Mitigation pursuant to this section shall be applied to all Supply Offers in the Real-Time Energy Market submitted by a Lead Market Participant that is determined to be a pivotal supplier in the Real-Time Energy Market.

III.A.5.5.4.2. Conduct Test.

A Resource shall fail the conduct test for general threshold commitment mitigation if the low Load Cost at Offer divided by the Low Load Cost at Reference Level is greater than 3.00.

III.A.5.5.4.3. Consequence of Failing Conduct Test.

If a Resource fails the general threshold commitment conduct test, then all financial parameters of its Supply Offer are set to their Reference Levels.

III.A.5.5.5. Constrained Area Commitment Mitigation.

III.A.5.5.5.1. Applicability.

Mitigation pursuant to this section shall be applied to any Resource determined to be within a constrained area in the Real-Time Energy Market.

III.A.5.5.5.2. Conduct Test.

A Resource shall fail the conduct test for constrained area commitment mitigation if the Low Load Cost at Offer divided by the Low Load Cost at Reference Level is greater than 1.25.

III.A.5.5.5.3. Consequence of Failing Test.

If a Supply Offer fails the constrained area commitment conduct test, then all financial parameters of its Supply Offer are set to their Reference Levels.

III.A.5.5.6. Reliability Commitment Mitigation.

III.A.5.5.6.1. Applicability.

Mitigation pursuant to this section shall be applied to Supply Offers for Resources that are (a) committed to provide, or Resources that are required to remain online to provide, one or more of the following:

i. local first contingency;
ii. local second contingency;
iii. VAR or voltage;
iv. distribution (Special Constraint Resource Service);
v. dual fuel resource auditing;

(b) otherwise manually committed by the ISO for reasons other than meeting anticipated load plus reserve requirements.

III.A.5.5.6.2. Conduct Test.

A Supply Offer shall fail the conduct test for local reliability commitment mitigation if the Low Load Cost at Offer divided by the Low Load Cost at Reference Level is greater than 1.10.

III.A.5.5.6.3. Consequence of Failing Test.

If a Supply Offer fails the local reliability commitment conduct test, it shall be evaluated for commitment based on an offer with all financial parameters set to their Reference Levels. This includes all offer blocks and all types of Start-Up Fees and the No-Load Fee. If a Resource is committed, then all financial parameters of its Supply Offer are set to their Reference Level.

III.A.5.5.7. Start-Up Fee and No-Load Fee Mitigation.

III.A.5.5.7.1. Applicability.

Mitigation pursuant to this section shall be applied to any Supply Offer submitted in the Day-Ahead Energy Market or Real-Time Energy Market if the resource is committed.

III.A.5.5.7.2. Conduct Test.

A Supply Offer shall fail the conduct test for Start-Up Fee and No-Load Fee mitigation if its Start-Up Fee or No-Load Fee divided by the Reference Level for that fee is greater than 3.

III.A.5.5.7.3. Consequence of Failing Conduct Test.

If a Supply Offer fails the conduct test, then all financial parameters of its Supply Offer shall be set to their Reference Levels.

III.A.5.5.8. Low Load Cost.

Low Load Cost, which is the cost of operating the Resource at its Economic Minimum Limit, is calculated as the sum of:

(a) If the Resource is starting from an offline state, the Start-Up Fee;
(b) The sum of the No Load Fees for the Commitment Period; and
(c) The sum of the hourly values resulting from the multiplication of the price of energy at the Resource's Economic Minimum Limit times its Economic Minimum Limit, for each hour of the Commitment Period.

All Supply Offer parameter values used in calculating the Low Load Cost are the values in place at the time the commitment decision is made.

Low Load Cost at Offer equals the Low Load Cost calculated with financial parameters of the Supply Offer as submitted by the Lead Market Participant.

Low Load Cost at Reference Level equals the Low Load Cost calculated with the financial parameters of the Supply Offer set to Reference Levels.

For Low Load Cost at Offer, the price of energy is the energy price parameter of the Resource's Supply Offer at the Economic Minimum Limit offer block. For Low Load Cost at Reference Level, the price of energy is the energy price parameter of the Resource's Reference Level at the Economic Minimum Limit offer block.

III.A.5.6. Duration of Energy Threshold Mitigation.

Any mitigation imposed pursuant to Sections III.A.5.5.1 “General Threshold Energy Mitigation” or III.A.5.5.2 “Constrained Area Energy Mitigation” is in effect for the following duration:

(a) in the Real-Time Energy Market, mitigation starts when the impact test violation occurs and remains in effect until there is one complete hour in which:

    i. for general threshold mitigation, the Market Participant whose Supply Offer is subject to mitigation is not a pivotal supplier; or,

    ii. for constrained area energy mitigation, the Resource is not located within a constrained area.

(b) in the Day-Ahead Energy Market (applicable only for Section III.A.5.5.2 “Constrained Area Energy Mitigation”), mitigation is in effect in each hour in which the impact test is violated.

Any mitigation imposed pursuant to Section III.A.5.5.3 “Manual Dispatch Energy Mitigation” is in effect for at least one hour until the earlier of either (a) the hour when manual dispatch is no longer in effect and the Resource returns to its Economic Minimum Limit, or (b) the hour when the energy price parameter of its Supply Offer at the Desired Dispatch Point is no longer greater than the Real-Time Price at the Resource’s Node.

III.A.5.7. Duration of Commitment Mitigation.

Any mitigation imposed pursuant to Sections III.A.5.5.4 “General Threshold Commitment Mitigation”, III.A.5.5.5 “Constrained Area Commitment Mitigation”, or III.A.5.5.6 “Reliability Commitment Mitigation” is in effect for the duration of the Commitment Period.

III.A.5.8. Duration of Start-Up Fee and No-Load Fee Mitigation.

Any mitigation imposed pursuant to Sections III.A.5.5.7 “Start-Up Fee and No-Load Fee Mitigation” is in effect for any hour in which the Supply Offer fails the conduct test in Section III.A.5.5.7.2.

III.A.5.9. Correction of Mitigation.

If the Internal Market Monitor determines that there are one or more errors in the mitigation applied in an Operating Day due to data entry, system or software errors by the ISO or the Internal Market Monitor, the Internal Market Monitor shall notify the market monitoring contacts specified by the Lead Market Participant within five Business Days of the applicable Operating Day. The ISO shall correct the error as

part of the Data Reconciliation Process by applying the correct values to the relevant Supply Offer in the settlement process.

The permissibility of correction of errors in mitigation, and the timeframes and procedures for permitted corrections, are addressed solely in this section and not in those sections of Market Rule 1 relating to settlement and billing processes.

III.A.5.10. Delay of Day-Ahead Energy Market Due to Mitigation Process.

The posting of the Day-Ahead Energy Market results may be delayed if necessary for the completion of mitigation procedures.

III.A.6. Physical and Financial Parameter Offer Thresholds.

Physical parameters of a Supply Offer are limited to thresholds specified in this section. Physical parameters are limited by the software accepting offers, except those that can be re-declared in real time during the Operating Day. Parameters that exceed the thresholds specified here but are not limited through the software accepting offers are subject to Internal Market Monitor review after the Operating Day and possible referral to the Commission under Section III.A.19 of this Appendix.

III.A.6.1. Time-Based Offer Parameters.

Supply Offer parameters that are expressed in time (i.e., Minimum Run Time, Minimum Down Time, Start-Up Time, and Notification Time) shall have a threshold of two hours for an individual parameter or six hours for the combination of the time-based offer parameters compared to the Resource's Reference Levels. Offers may not exceed these thresholds in a manner that reduce the flexibility of the Resource. To determine if the six hour threshold is exceeded, all time-based offer parameters will be summed for each start-up state (hot, intermediate and cold). If the sum of the time-based offer parameters for a start-up state exceeds six hours above the sum of the Reference Levels for those offer parameters, then the six hour threshold is exceeded.

III.A.6.2. Financial Offer Parameters.

The Start-Up Fee and the No-Load Fee values of a Resource's Supply Offer may be no greater than three times the Start-Up Fee and No-Load Fee Reference Level values for the Resource. In the event a fuel price has been submitted under Section III.A.3.4, the Start-Up Fee and No-Load Fee for the associated Supply Offer shall be limited in a Real-Time Offer Change. The limit shall be the percent increase in the new fuel price, relative to the fuel price otherwise used by the Internal Market Monitor, multiplied by the

Start-Up Fee or No-Load Fee from the Re-Offer Period. Absent a fuel price adjustment, a Start-Up Fee or No-Load Fee may be changed in a Real-Time Offer Change to no more than the Start-Up Fee and No-Load Fee values submitted for the Re-Offer Period.

III.A.6.3. Other Offer Parameters.

Non-financial or non-time-based offer parameters shall have a threshold of a 100% increase, or greater, for parameters that are minimum values, or a 50% decrease, or greater, for parameters that are maximum values (including, but not limited to, ramp rates, Economic Maximum Limits and maximum starts per day) compared to the Resource's Reference Levels.

Offer parameters that are limited by performance caps or audit values imposed by the ISO are not subject to the provisions of this section.

III.A.7. Calculation of Resource Reference Levels for Physical Parameters and Financial Parameters of Resources.

Market Participants are responsible for providing the Internal Market Monitor with all the information and data necessary for the Internal Market Monitor to calculate up-to-date Reference Levels for each of a Market Participant's Resources.

III.A.7.1. Methods for Determining Reference Levels for Physical Parameters.

The Internal Market Monitor will calculate a Reference Level for each element of a bid or offer that is expressed in units other than dollars (such as time-based or quantity level bid or offer parameters) on the basis of one or more of the following:

(a) Original equipment manufacturer (OEM) operating recommendations and performance data for all Resource types in the New England Control Area, grouped by unit classes, physical parameters and fuel types.

(b) Applicable environmental operating permit information currently on file with the issuing environmental regulatory body.

(c) Verifiable Resource physical operating characteristic data, including but not limited to facility and/or Resource operating guides and procedures, historical operating data and any verifiable documentation related to the Resource, which will be reviewed in consultation with the Market Participant.

III.A.7.2. Methods for Determining Reference Levels for Financial Parameters of Offers.

The Reference Levels for Start-Up Fees, No-Load Fees, Interruption Costs and offer blocks will be calculated separately and assuming no costs from one component are included in another component.

III.A.7.2.1. Order of Reference Level Calculation.

The Internal Market Monitor will calculate a Reference Level for each offer block of an offer according to the following hierarchy, under which the first method that can be calculated is used:

(a) accepted offer-based Reference Levels pursuant to Section III.A.7.3;

(b) LMP-based Reference Levels pursuant to Section III.A.7.4; and,

(c) cost-based Reference Levels pursuant to Section III.A.7.5.

III.A.7.2.2. Circumstances in Which Cost-Based Reference Levels Supersede the Hierarchy of Reference Level Calculation.

In the following circumstances, cost-based Reference Levels shall be used notwithstanding the hierarchy specified in Section III.A.7.2.1.

(a) When in any hour the cost-based Reference Level is higher than either the accepted offer-based or LMP-based Reference Level.

(b) When the Supply Offer parameter is a Start-Up Fee or the No-Load Fee.

(c) For any Operating Day for which the Lead Market Participant requests the cost-based Reference Level.

(d) For any Operating Day for which, during the previous 90 days:

  (i) the Resource has been flagged for VAR, SCR, or as a Local Second Contingency Protection Resource for any hour in the Day-Ahead Energy Market or the Real-Time Energy Market, and;

  (ii) the ratio of the sum of the operating hours for days for which the Resource has been flagged during the previous 90 days in which the number of hours operated out of economic merit order in the Day-Ahead Energy Market and the Real-Time Energy Market exceed the number of hours operated in economic merit order in the Day-Ahead Energy Market and Real-Time Energy Market, to the total number of operating hours in the Day-Ahead Energy Market and Real-Time Energy Market during the previous 90 days is greater than or equal to 50 percent.

(e) When in any hour the incremental energy parameter of an offer, including adjusted offers pursuant to Section III.2.4, is greater than $1,000/MWh.

For the purposes of this subsection:

i. A flagged day is any day in which the Resource has been flagged for VAR, SCR, or as a Local Second Contingency Protection Resource for any hour in either the Day-Ahead Energy Market or the Real-Time Energy Market.

ii. Operating hours are the hours in the Day-Ahead Energy Market for which a Resource has cleared output (MW) greater than zero and hours in the Real-Time Energy Market for which a Resource has metered output (MW) greater than zero. For days for which Real-time Energy Market metered values are not yet available in the ISO's or the Internal Market Monitor's systems, telemetered values will be used.

iii. Self-scheduled hours will be excluded from all of the calculations described in this subsection, including the determination of operating hours.

iv. The determination as to whether a Resource operated in economic merit order during an hour will be based on the energy offer block within which the Resource is operating.

(e) The Market Participant submits a fuel price pursuant to Section III.A.3.4. When the Market Participant submits a fuel price for any hour of a Supply Offer in the Day-Ahead Energy Market or Re-Offer Period, then the cost-based Reference Level is used for the entire Operating Day. If a fuel price is submitted for a Supply Offer after the close of the Re-Offer Period for the next Operating Day or for the current Operating Day, then the cost-based Reference Level for the Supply Offer is used from the time of the submittal to the end of the Operating Day.

(f) When the Market Participant submits a change to any of the following parameters of the Supply Offer after the close of the Re-Offer Period:

(i) hot, intermediate, or cold Start-Up Fee, or a corresponding fuel blend,

(ii) No-Load Fee or its corresponding fuel blends,

(iii) whether to include the Start-Up Fee and No-Load Fee in the Supply Offer,

(iv) the quantity or price value of any Block in the Supply Offer or its corresponding fuel blends, and

(v) whether to use the offer slope for the Supply Offer,

then, the cost-based Reference Level for the Supply Offer will be used from the time of the submittal to the end of the Operating Day.

III.A.7.3. Accepted Offer-Based Reference Level.

The Internal Market Monitor shall calculate the accepted offer-based Reference Level as the lower of the mean or the median of a generating Resource's Supply Offers that have been accepted and are part of the seller's Day-Ahead Generation Obligation or Real-Time Generation Obligation in competitive periods over the previous 90 days, adjusted for changes in fuel prices utilizing fuel indices generally applicable for the location and type of Resource. For purposes of this section, a competitive period is an Operating Day in which the Resource is scheduled in economic merit order.

III.A.7.4. LMP-Based Reference Level.

The Internal Market Monitor shall calculate the LMP-based Reference Level as the mean of the LMP at the Resource's Node during the lowest-priced 25% of the hours that the Resource was dispatched over the previous 90 days for similar hours (on-peak or off-peak), adjusted for changes in fuel prices.

III.A.7.5. Cost-Based Reference Level.

The Internal Market Monitor shall calculate cost-based Reference Levels taking into account information on costs provided by the Market Participant though the consultation process prescribed in Section III.A.3.

The following criteria shall be applied to estimates of cost:

(a) The provision of cost estimates by a Market Participant shall conform with the timing and requirements of Section III.A.3 "Consultation Prior to Determination of Reference Levels for Physical and Financial Parameters of Resources".

(b) Costs must be documented.

(c) All cost estimates shall be based on estimates of current market prices or replacement costs and not inventory costs wherever possible. All cost estimates, including opportunity cost estimates, must be quantified and analytically supported.

(d) When market prices or replacement costs are unavailable, cost estimates shall identify whether the reported costs are the result of a product or service provided by an Affiliate of the Market Participant.

(e) The Internal Market Monitor will evaluate cost information provided by the Market Participant in comparison to other information available to the Internal Market Monitor. Reference Levels associated with Resources for which a fuel price has been submitted under Section III.A.3.4 shall be calculated using the lower of the submitted fuel price or a price, calculated by the Internal Market Monitor, that takes account of the following factors and conditions:

i. Fuel market conditions, including the current spread between bids and asks for current fuel delivery, fuel trading volumes, near-term price quotes for fuel, expected natural gas heating demand, and Market Participant-reported quotes for trading and fuel costs; and
ii. Fuel delivery conditions, including current and forecasted fuel delivery constraints and current line pack levels for natural gas pipelines.

III.A.7.5.1. Estimation of Incremental Operating Cost.

The Internal Market Monitor's determination of a Resource's marginal costs shall include an assessment of the Resource's incremental operating costs in accordance with the following formulas,

Incremental Energy/Reduction:
(incremental heat rate * fuel costs) + (emissions rate * emissions allowance price) + variable operating and maintenance costs + opportunity costs.

Opportunity costs may include, but are not limited to, economic costs associated with complying with:

(a) emissions limits;
(b) water storage limits;
(c) other operating permits that limit production of energy; and
(d) reducing electricity consumption.

No-Load:
(no-load fuel use * fuel costs) + (no-load emissions * emission allowance price)
+ no-load variable operating and maintenance costs + other no-load costs that are not fuel, emissions or variable and maintenance costs.

Start-Up/Interruption:
(start-up fuel use * fuel costs) + (start-up emissions * emission allowance price) + start-up variable and maintenance costs + other start-up costs that are not fuel, emissions or variable and maintenance costs.

III.A.8. [Reserved.]

III.A.9. Regulation.

The Internal Market Monitor will monitor the Regulation market for conduct that it determines constitutes an abuse of market power. If the Internal Market Monitor identifies any such conduct, it may make a filing under Section 205 of the Federal Power Act with the Commission requesting authorization to apply appropriate mitigation measures or to revise Market Rule 1 to address such conduct (or both). The Internal Market Monitor may make such a filing at any time it deems necessary, and may request expedited treatment from the Commission. Any such filing shall identify the particular conduct the Internal Market Monitor believes warrants mitigation or revisions to Market Rule 1 (or both), shall propose a specific mitigation measure for the conduct or revision to Market Rule 1 (or both), and shall set forth the Internal Market Monitor's justification for imposing that mitigation measure or revision to Market Rule 1 (or both).

III.A.10. Demand Bids.

The Internal Market Monitor will monitor the Energy Market as outlined below:

(a) LMPs in the Day-Ahead Energy Market and Real-Time Energy Market shall be monitored to determine whether there is a persistent hourly deviation in any location that would not be expected in a workably competitive market.

(b) The Internal Market Monitor shall compute the average hourly deviation between Day-Ahead Energy Market and Real-Time Energy Market LMPs, measured as: $(LMP_{\text{real time}} / LMP_{\text{day ahead}}) - 1$. The average hourly deviation shall be computed over a rolling four-week period or such other period determined by the Internal Market Monitor.

(c) The Internal Market Monitor shall estimate and monitor the average percentage of each Market Participant's bid to serve load scheduled in the Day-Ahead Energy Market, using a methodology intended to identify a sustained pattern of under-bidding as accurately as deemed practicable. The average percentage will be computed over a specified time period determined by the Internal Market Monitor.

If the Internal Market Monitor determines that: (i) The average hourly deviation is greater than ten percent (10%) or less than negative ten percent (-10%), (ii) one or more Market Participants on behalf of one or more LSEs have been purchasing a substantial portion of their loads with purchases in the Real-Time Energy Market, (iii) this practice has contributed to an unwarranted divergence of LMPs between

the two markets, and (iv) this practice has created operational problems, the Internal Market Monitor may make a filing under Section 205 of the Federal Power Act with the Commission requesting authorization to apply appropriate mitigation measures or to revise Market Rule 1 to address such conduct (or both). The thresholds identified above shall not limit the Internal Market Monitor's authority to make such a filing. The Internal Market Monitor may make such a filing at any time it deems necessary, and may request expedited treatment from the Commission. Any such filing shall identify the particular conduct that the Internal Market Monitor believes warrants mitigation or revisions to Market Rule 1 (or both), shall propose a specific mitigation measure for the conduct or revision to Market Rule 1 (or both), and shall set forth the Internal Market Monitor's justification for imposing that mitigation measure or revision to Market Rule 1 (or both).

III.A.11. Mitigation of Increment Offers and Decrement Bids.

III.A.11.1. Purpose.

The provisions of this section specify the market monitoring and mitigation measures applicable to Increment Offers and Decrement Bids. An Increment Offer is one to supply energy and a Decrement Bid is one to purchase energy, in either such case not being backed by physical load or generation and submitted in the Day-Ahead Energy Market in accordance with the procedures and requirements specified in Market Rule 1 and the ISO New England Manuals.

III.A.11.2. Implementation.

III.A.11.2.1. Monitoring of Increment Offers and Decrement Bids.

Day-Ahead LMPs and Real-Time LMPs in each Load Zone or Node, as applicable, shall be monitored to determine whether there is a persistent hourly deviation in the LMPs that would not be expected in a workably competitive market. The Internal Market Monitor shall compute the average hourly deviation between Day-Ahead LMPs and Real-Time LMPs, measured as:

$(LMP_{\text{real time}} / LMP_{\text{day ahead}}) - 1.$

The average hourly deviation shall be computed over a rolling four-week period or such other period determined by the Internal Market Monitor to be appropriate to achieve the purpose of this mitigation measure.

III.A.11.3. Mitigation Measures.

If the Internal Market Monitor determines that (i) the average hourly deviation computed over a rolling four week period is greater than ten percent (10%) or less than negative ten percent (-10%), and (ii) the bid and offer practices of one or more Market Participants has contributed to a divergence between LMPs in the Day-Ahead Energy Market and Real-Time Energy Market, then the following mitigation measure may be imposed:

The Internal Market Monitor may limit the hourly quantities of Increment Offers for supply or Decrement Bids for load that may be offered in a Location by a Market Participant, subject to the following provisions:

(i) The Internal Market Monitor shall, when practicable, request explanations of the relevant bid and offer practices from any Market Participant submitting such bids.

(ii) Prior to imposing a mitigation measure, the Internal Market Monitor shall notify the affected Market Participant of the limitation.

(iii) The Internal Market Monitor, with the assistance of the ISO, will restrict the Market Participant for a period of six months from submitting any virtual transactions at the same Node(s), and/or electrically similar Nodes to, the Nodes where it had submitted the virtual transactions that contributed to the unwarranted divergence between the LMPs in the Day-Ahead Energy Market and Real-Time Energy Market.

III.A.11.4. Monitoring and Analysis of Market Design and Rules.

The Internal Market Monitor shall monitor and assess the impact of Increment Offers and Decrement Bids on the competitive structure and performance, and the economic efficiency of the New England Markets. Such monitoring and assessment shall include the effects, if any, on such bids and offers of any mitigation measures specified in this Market Rule 1.

III.A.12. Cap on FTR Revenues.

If a holder of an FTR between specified delivery and receipt Locations (i) had an Increment Offer and/or Decrement Bid that was accepted by the ISO for an applicable hour in the Day-Ahead Energy Market for delivery or receipt at or near delivery or receipt Locations of the FTR; and (ii) the result of the acceptance of such Increment Offer or Decrement Bid is that the difference in LMP in the Day-Ahead Energy Market between such delivery and receipt Locations is greater than the difference in LMP between such delivery and receipt Locations in the Real-Time Energy Market, then the Market Participant shall not receive any Transmission Congestion Credit associated with such FTR in such hour, in excess of one divided by the

number of hours in the applicable month multiplied by the amount originally paid for the FTR in the FTR Auction. A Location shall be considered at or near the FTR delivery or receipt Location if seventy-five % or more of the energy injected or withdrawn at that Location and which is withdrawn or injected at another Location is reflected in the constrained path between the subject FTR delivery and receipt Locations that were acquired in the FTR Auction.

III.A.13. Additional Internal Market Monitor Functions Specified in Tariff.

III.A.13.1. Review of Offers and Bids in the Forward Capacity Market.

In accordance with the following provisions of Section III.13 of Market Rule 1, the Internal Market Monitor is responsible for reviewing certain bids and offers made in the Forward Capacity Market. Section III.13 of Market Rule 1 specifies the nature and detail of the Internal Market Monitor's review and the consequences that will result from the Internal Market Monitor's determination following such review.

(a) [Reserved].

(b) Section III.13.1.2.3.1.6.3 - Internal Market Monitor review of Static De-List Bids, Permanent De-List Bids, and Retirement De-List Bids from an Existing Generating Capacity Resource that is associated with a Station having Common Costs.

(c) Section III.13.1.2.3.2 - Review by Internal Market Monitor of Bids from Existing Generating Capacity Resources.

(d) Section III.13.1.3.3A(d) - Review by Internal Market Monitor of offers from Existing Import Capacity Resources.

(e) Section III.13.1.3.5.6 - Review by Internal Market Monitor of Offers from New Import Capacity Resources.

(f) Section III.13.1.7 - Internal Market Monitor review of summer and winter Seasonal Claimed Capability values.

III.A.13.2. Supply Offers and Demand Bids Submitted for Reconfiguration Auctions in the Forward Capacity Market.

Section III.13.4 of Market Rule 1 addresses reconfiguration auctions in the Forward Capacity Market. As addressed in Section III.13.4.2 of Market Rule 1, a supply offer or demand bid submitted for a reconfiguration auction shall not be subject to mitigation by the Internal Market Monitor.

III.A.13.3. Monitoring of Transmission Facility Outage Scheduling.

Appendix G of Market Rule 1 addresses the scheduling of outages for transmission facilities. The Internal Market Monitor shall monitor the outage scheduling activities of the Transmission Owners. The Internal Market Monitor shall have the right to request that each Transmission Owner provide information to the Internal Market Monitor concerning the Transmission Owner's scheduling of transmission facility outages, including the repositioning or cancellation of any interim approved or approved outage, and the Transmission Owner shall provide such information to the Internal Market Monitor in accordance with the ISO New England Information Policy.

III.A.13.4. Monitoring of Forward Reserve Resources.

The Internal Market Monitor will receive information that will identify Forward Reserve Resources, the Forward Reserve Threshold Price, and the assigned Forward Reserve Obligation. Prior to mitigation of Supply Offers or Demand Bids associated with a Forward Reserve Resource, the Internal Market Monitor shall consult with the Market Participant in accordance with Section III.A.3 of this ***Appendix A***. The Internal Market Monitor and the Market Participant shall consider the impact on meeting any Forward Reserve Obligations in those consultations. If mitigation is imposed, any mitigated offers shall be used in the calculation of qualifying megawatts under Section III.9.6.4 of Market Rule 1.

III.A.13.5. Imposition of Sanctions.

Appendix B of Market Rule 1 sets forth the procedures and standards under which sanctions may be imposed for certain violations of Market Participants' obligations under the ISO New England Filed Documents and other ISO New England System Rules. The Internal Market Monitor shall administer ***Appendix B*** in accordance with the provisions thereof.

III.A.14. Treatment of Supply Offers for Resources Subject to a Cost-of-Service Agreement.

Article 5 of the form of Cost-of-Service Agreement in ***Appendix I*** to Market Rule 1 addresses the monitoring of resources subject to a cost-of-service agreement by the Internal Market Monitor and External Market Monitor. Pursuant to Section 5.2 of Article 5 of the Form of Cost-of-Service Agreement, after consultation with the Lead Market Participant, Supply Offers that exceed Stipulated Variable Cost as determined in the agreement are subject to adjustment by the Internal Market Monitor to Stipulated Variable Cost.

III.A.15. Request for Additional Cost Recovery.

III.A.15.1. Cost Recovery Request Following Capping.

If as a result of an offer being capped under Section III.1.9, a Market Participant believes that it will not recover the fuel and variable operating and maintenance costs of the Resource, as reflected in the offer, for the hours of the Operating Day during which the offer was capped, the Market Participant may, within 20 days of the receipt of the first Invoice issued containing credits or charges for the applicable Operating Day, submit an additional cost recovery request to the Internal Market Monitor.

A request under this Section III.A.15 may seek recovery of additional costs incurred for the duration of the period of time for which the Resource was operated at the cap.

III.A.15.1.1. Timing and Contents of Request.

Within 20 days of the receipt of the first Invoice containing credits or charges for the applicable Operating Day, a Market Participant requesting additional cost recovery under this Section III.A.15.1 shall submit to the Internal Market Monitor a request in writing detailing: (i) the actual fuel and variable operating and maintenance costs for the Resource for the applicable Operating Days, with supporting data, documentation and calculations for those costs; and (ii) an explanation of why the actual costs of operating the Resource exceeded the capped costs.

III.A.15.1.2. Review by Internal Market Monitor.

To evaluate a Market Participant's request, the Internal Market Monitor shall use the data, calculations and explanations provided by the Market Participant to verify the actual fuel and variable operating and maintenance costs for the Resource for the applicable Operating Days, using the same standards and methodologies the Internal Market Monitor uses to evaluate requests to update Reference Levels under Section III.A.3 of Appendix A. To the extent the Market Participant's request warrants additional cost recovery, the Internal Market Monitor shall reflect that adjustment in the Resource's Reference Levels for the period covered by the request. The ISO shall then re-apply the cost verification and capping formulas in Section III.1.9 using the updated Reference Levels to re-calculate the adjustments to the Market Participant's offers required thereunder, and then shall calculate additional cost recovery using the adjusted offer values.

Within 20 days of the receipt of a completed submittal, the Internal Market Monitor shall provide a written response to the Market Participant's request, detailing (i) the extent to which it agrees with the request with supporting explanation, and (ii) a calculation of the additional cost recovery. Changes to

credits and charges resulting from an additional cost recovery request shall be included in the Data Reconciliation Process.

III.A.15.1.3. Cost Allocation.

The ISO shall allocate charges to Market Participants for payment of any additional cost recovery granted under this Section III.A.15.1 in accordance with the cost allocation provisions of Market Rule 1 that otherwise would apply to payments for the services provided based on the Resource's actual dispatch for the Operating Days in question.

III.A.15.2. Section 205 Filing Right.

If either

(a) as a result of mitigation applied to a Resource under this ***Appendix A*** for all or part of one or more Operating Days, or

(b) in the absence of mitigation, as a result of a request under Section III.A.15.1 being denied in whole or in part,

a Market Participant believes that it will not recover the fuel and variable operating and maintenance costs of the Resource, as reflected in the offer, for the hours of the Operating Day during which the offer was mitigated or the Section III.A.15.1 request was denied, the Market Participant may submit a filing to the Commission seeking recovery of those costs pursuant to Section 205 of the Federal Power Act. For filings to address cost recovery under Section III.A.15.2(a), the filing must be made within sixty days of receipt of the first Invoice issued containing credits or charges for the applicable Operating Day. For filings to address cost recovery under Section III.A.15.2(b), the filing must be made within sixty days of receipt of the first Invoice issued that reflects the denied request for additional cost recovery under Section III.A.15.1.

A request under this Section III.A.15.2 may seek recovery of additional costs incurred during the following periods: (a) if as a result of mitigation, costs incurred for the duration of the mitigation event, and (b) if as a result of having a Section III.A.15.1 request denied, costs incurred for the duration of the period of time addressed in the Section III.A.15.1 request.

III.A.15.2.1. Contents of Filing.

Any Section 205 filing made pursuant to this section shall include: (i) the actual fuel and variable operating and maintenance costs for the Resource for the applicable Operating Days, with supporting data

and calculations for those costs; (ii) an explanation of (a) why the actual costs of operating the Resource exceeded the Reference Level costs or, (b) in the absence of mitigation, why the actual costs of operating the Resource, as reflected in the original offer and to the extent not recovered under Section III.A.15.1, exceeded the costs as reflected in the capped offer; (iii) the Internal Market Monitor's written explanation provided pursuant to Section III.A.15.3; and (iv) all requested regulatory costs in connection with the filing.

III.A.15.2.2. Review by Internal Market Monitor Prior to Filing.

Within twenty days of the receipt of the applicable Invoice, a Market Participant that intends to make a Section 205 filing pursuant to this Section III.A.15.2 shall submit to the Internal Market Monitor the information and explanation detailed in Section III.A.15.2.1 (i) and (ii) that is to be included in the Section 205 filing. Within twenty days of the receipt of a completed submittal, the Internal Market Monitor shall provide a written explanation of the events that resulted in the Section III.A.15.2 request for additional cost recovery. The Market Participant shall include the Internal Market Monitor's written explanation in the Section 205 filing made pursuant to this Section III A.15.2.

III.A.15.2.3. Cost Allocation.

In the event that the Commission accepts a Market Participant's filing for cost recovery under this section, the ISO shall allocate charges to Market Participants for payment of those costs in accordance with the cost allocation provisions of Market Rule 1 that otherwise would apply to payments for the services provided based on the Resource's actual dispatch for the Operating Days in question.

III.A.16. ADR Review of Internal Market Monitor Mitigation Actions.

III.A.16.1. Actions Subject to Review.

A Market Participant may obtain prompt Alternative Dispute Resolution ("ADR") review of any Internal Market Monitor mitigation imposed on a Resource as to which that Market Participant has bidding or operational authority. A Market Participant must seek review pursuant to the procedure set forth in ***Appendix D*** to this Market Rule 1, but in all cases within the time limits applicable to billing adjustment requests. These deadlines are currently specified in the ISO New England Manuals. Actions subject to review are:

- Imposition of a mitigation remedy.

- Continuation of a mitigation remedy as to which a Market Participant has submitted material evidence of changed facts or circumstances. (Thus, after a Market Participant has unsuccessfully challenged imposition of a mitigation remedy, it may challenge the continuation of that mitigation in a subsequent ADR review on a showing of material evidence of changed facts or circumstances.)

III.A.16.2. Standard of Review.

On the basis of the written record and the presentations of the Internal Market Monitor and the Market Participant, the ADR Neutral shall review the facts and circumstances upon which the Internal Market Monitor based its decision and the remedy imposed by the Internal Market Monitor. The ADR Neutral shall remove the Internal Market Monitor's mitigation only if it concludes that the Internal Market Monitor's application of the Internal Market Monitor mitigation policy was clearly erroneous. In considering the reasonableness of the Internal Market Monitor's action, the ADR Neutral shall consider whether adequate opportunity was given to the Market Participant to present information, any voluntary remedies proposed by the Market Participant, and the need of the Internal Market Monitor to act quickly to preserve competitive markets.

III.A.17. Reporting.

III.A.17.1. Data Collection and Retention.

Market Participants shall provide the Internal Market Monitor and External Market Monitor with any and all information within their custody or control that the Internal Market Monitor or External Market Monitor deems necessary to perform its obligations under this ***Appendix A***, subject to applicable confidentiality limitations contained in the ISO New England Information Policy. This would include a Market Participant's cost information if the Internal Market Monitor or External Market Monitor deems it necessary, including start up, no-load and all other actual marginal costs, when needed for monitoring or mitigation of that Market Participant. Additional data requirements may be specified in the ISO New England Manuals. If for any reason the requested explanation or data is unavailable, the Internal Market Monitor and External Market Monitor will use the best information available in carrying out their responsibilities. The Internal Market Monitor and External Market Monitor may use any and all information they receive in the course of carrying out their market monitor and mitigation functions to the extent necessary to fully perform those functions.

Market Participants must provide data and any other information requested by the Internal Market Monitor that the Internal Market Monitor requests to determine:

(a) the opportunity costs associated with Demand Reduction Offers;

(b) the accuracy of Demand Response Baselines;

(c) the method used to achieve a demand reduction, and;

(d) the accuracy of metered demand reported to the ISO.

III.A.17.2. Periodic Reporting by the ISO and Internal Market Monitor.

III.A.17.2.1. Monthly Report.

The ISO will prepare a monthly report, which will be available to the public both in printed form and electronically, containing an overview of the market's performance in the most recent period.

III.A.17.2.2. Quarterly Report.

The Internal Market Monitor will prepare a quarterly report consisting of market data regularly collected by the Internal Market Monitor in the course of carrying out its functions under this ***Appendix A*** and analysis of such market data. Final versions of such reports shall be disseminated contemporaneously to the Commission, the ISO Board of Directors, the Market Participants, and state public utility commissions for each of the six New England states, provided that in the case of the Market Participants and public utility commissions, such information shall be redacted as necessary to comply with the ISO New England Information Policy. The format and content of the quarterly reports will be updated periodically through consensus of the Internal Market Monitor, the Commission, the ISO, the public utility commissions of the six New England States and Market Participants. The entire quarterly report will be subject to confidentiality protection consistent with the ISO New England Information Policy and the recipients will ensure the confidentiality of the information in accordance with state and federal laws and regulations. The Internal Market Monitor will make available to the public a redacted version of such quarterly reports. The Internal Market Monitor, subject to confidentiality restrictions, may decide whether and to what extent to share drafts of any report or portions thereof with the Commission, the ISO, one or more state public utility commission(s) in New England or Market Participants for input and verification before the report is finalized. The Internal Market Monitor shall keep the Market Participants informed of the progress of any report being prepared pursuant to the terms of this ***Appendix A.***

III.A.17.2.3. Reporting on General Performance of the Forward Capacity Market.

The performance of the Forward Capacity Market, including reconfiguration auctions, shall be subject to the review of the Internal Market Monitor. No later than 180 days after the completion of the second Forward Capacity Auction, the Internal Market Monitor shall file with the Commission and post to the ISO's website a full report analyzing the operations and effectiveness of the Forward Capacity Market. Thereafter, the Internal Market Monitor shall report on the functioning of the Forward Capacity Market in its annual markets report in accordance with the provisions of Section III.A.17.2.4 of this ***Appendix A***.

III.A.17.2.4. Annual Review and Report by the Internal Market Monitor.

The Internal Market Monitor will prepare an annual state of the market report on market trends and the performance of the New England Markets and will present an annual review of the operations of the New England Markets. The annual report and review will include an evaluation of the procedures for the determination of energy, reserve and regulation clearing prices, NCPC costs and the performance of the Forward Capacity Market and FTR Auctions. The review will include a public forum to discuss the performance of the New England Markets, the state of competition, and the ISO's priorities for the coming year. In addition, the Internal Market Monitor will arrange a non-public meeting open to appropriate state or federal government agencies, including the Commission and state regulatory bodies, attorneys general, and others with jurisdiction over the competitive operation of electric power markets, subject to the confidentiality protections of the ISO New England Information Policy, to the greatest extent permitted by law.

III.A.17.2.5. Additional Ad Hoc Reporting on Performance and Competiveness of Markets

Commencing on June 1, 2024, in furtherance of its functions under Section III.A.2 of this Appendix A, including without limitation Sections III.A.2.3 (e) and (k) therein, the Internal Market Monitor shall perform independent evaluations and prepare ad hoc reports on the overall competitiveness and performance of the New England Markets or particular aspects of the New England Markets, including the competitiveness and performance of a major market design change. The Internal Market Monitor shall have the sole discretion to determine when to prepare an ad hoc report and may prepare such report on its own initiative or pursuant to a request by the ISO, New England state public utility commissions or one or more Market Participants. However, the Internal Market Monitor will report on the competitiveness and performance of any new major market design change within one to three years, respectively, of the effective date of

operation of the market design change, or as soon as adequate data becomes available. While the Internal Market Monitor may solicit and/or receive input of the External Market Monitor, Market Participants and other stakeholders, including New England state public utility commissions, the methodology and criteria used to conduct its independent analysis shall be at the sole discretion of the Internal Market Monitor. The Internal Market Monitor shall describe its methodology and criteria used in an ad hoc report of its significant findings and, if any, recommendations. The Internal Market Monitor shall file with the Commission and post to the ISO's website a final version of an ad hoc report. Thereafter, the Internal Market Monitor shall continue to report on the competitiveness and performance of any market design change that has been the subject of an ad hoc report in its quarterly and/or annual reports under Sections III.A.17.2.2 and III.A.17.2.4.

III.A.17.3. Periodic Reporting by the External Market Monitor.

The External Market Monitor will perform independent evaluations and prepare annual and ad hoc reports on the overall competitiveness and efficiency of the New England Markets or particular aspects of the New England Markets, including the adequacy of ***Appendix A***. The External Market Monitor shall have the sole discretion to determine whether and when to prepare ad hoc reports and may prepare such reports on its own initiative or pursuant to requests by the ISO, state public utility commissions or one or more Market Participants. Final versions of such reports shall be disseminated contemporaneously to the Commission, the ISO Board of Directors, the Market Participants, and state public utility commissions for each of the six New England states, provided that in the case of the Market Participants and public utility commissions, such information shall be redacted as necessary to comply with the ISO New England Information Policy. Such reports shall, at a minimum, include:

(i) Review and assessment of the practices, market rules, procedures, protocols and other activities of the ISO insofar as such activities, and the manner in which the ISO implements such activities, affect the competitiveness and efficiency of New England Markets.

(ii) Review and assessment of the practices, procedures, protocols and other activities of any independent transmission company, transmission provider or similar entity insofar as its activities affect the competitiveness and efficiency of the New England Markets.

(iii) Review and assessment of the activities of Market Participants insofar as these activities affect the competitiveness and efficiency of the New England Markets.

(iv) Review and assessment of the effectiveness of ***Appendix A*** and the administration of ***Appendix A*** by the Internal Market Monitor for consistency and compliance with the terms of ***Appendix A.***

(v) Review and assessment of the relationship of the New England Markets with any independent transmission company and with adjacent markets.

The External Market Monitor, subject to confidentiality restrictions, may decide whether and to what extent to share drafts of any report or portions thereof with the Commission, the ISO, one or more state public utility commission(s) in New England or Market Participants for input and verification before the report is finalized. The External Market Monitor shall keep the Market Participants informed of the progress of any report being prepared.

III.A.17.4. Other Internal Market Monitor or External Market Monitor Communications With Government Agencies.

III.A.17.4.1. Routine Communications.

The periodic reviews are in addition to any routine communications the Internal Market Monitor or External Market Monitor may have with appropriate state or federal government agencies, including the Commission and state regulatory bodies, attorneys general, and others with jurisdiction over the competitive operation of electric power markets.

III.A.17.4.2. Additional Communications.

The Internal Market Monitor and External Market Monitor are not a regulatory or enforcement agency. However, they will monitor market trends, including changes in Resource ownership as well as market performance. In addition to the information on market performance and mitigation provided in the monthly, quarterly and annual reports the External Market Monitor or Internal Market Monitor shall:

(a) Inform the jurisdictional state and federal regulatory agencies, as well as the Markets Committee, if the External Market Monitor or Internal Market Monitor determines that a market problem appears to be developing that will not be adequately remediable by existing market rules or mitigation measures;

(b) If the External Market Monitor or Internal Market Monitor receives information from any entity regarding an alleged violation of law, refer the entity to the appropriate state or federal agencies;

(c) If the External Market Monitor or Internal Market Monitor reasonably concludes, in the normal course of carrying out its monitoring and mitigation responsibilities, that certain

market conduct constitutes a violation of law, report these matters to the appropriate state and federal agencies; and,

(d) Provide the names of any companies subjected to mitigation under these procedures as well as a description of the behaviors subjected to mitigation and any mitigation remedies or sanctions applied.

III.A.17.4.3. Confidentiality.

Information identifying particular participants required or permitted to be disclosed to jurisdictional bodies under this section shall be provided in a confidential report filed under Section 388.112 of the Commission regulations and corresponding provisions of other jurisdictional agencies. The Internal Market Monitor will include the confidential report with the quarterly submission it provides to the Commission pursuant to Section III.A.17.2.2.

III.A.17.5. Other Information Available from Internal Market Monitor and External Market Monitor on Request by Regulators.

The Internal Market Monitor and External Market Monitor will normally make their records available as described in this paragraph to authorized state or federal agencies, including the Commission and state regulatory bodies, attorneys general and others with jurisdiction over the competitive operation of electric power markets ("authorized government agencies"). With respect to state regulatory bodies and state attorneys general ("authorized state agencies"), the Internal Market Monitor and External Market Monitor shall entertain information requests for information regarding general market trends and the performance of the New England Markets, but shall not entertain requests that are designed to aid enforcement actions of a state agency. The Internal Market Monitor and External Market Monitor shall promptly make available all requested data and information that they are permitted to disclose to authorized government agencies under the ISO New England Information Policy. Notwithstanding the foregoing, in the event an information request is unduly burdensome in terms of the demands it places on the time and/or resources of the Internal Market Monitor or External Market Monitor, the Internal Market Monitor or External Market Monitor shall work with the authorized government agency to modify the scope of the request or the time within which a response is required, and shall respond to the modified request.

The Internal Market Monitor and External Market Monitor also will comply with compulsory process, after first notifying the owner(s) of the items and information called for by the subpoena or civil investigative demand and giving them at least ten Business Days to seek to modify or quash the compulsory process. If an authorized government agency makes a request in writing, other than

compulsory process, for information or data whose disclosure to authorized government agencies is not permitted by the ISO New England Information Policy, the Internal Market Monitor and External Market Monitor shall notify each party with an interest in the confidentiality of the information and shall process the request under the applicable provisions of the ISO New England Information Policy. Requests from the Commission for information or data whose disclosure is not permitted by the ISO New England Information Policy shall be processed under Section 3.2 of the ISO New England Information Policy. Requests from authorized state agencies for information or data whose disclosure is not permitted by the ISO New England Information Policy shall be processed under Section 3.3 of the ISO New England Information Policy. In the event confidential information is ultimately released to an authorized state agency in accordance with Section 3.3 of the ISO New England Information Policy, any party with an interest in the confidentiality of the information shall be permitted to contest the factual content of the information, or to provide context to such information, through a written statement provided to the Internal Market Monitor or External Market Monitor and the authorized state agency that has received the information.

III.A.18. Ethical Conduct Standards.

III.A.18.1. Compliance with ISO New England Inc. Code of Conduct.
The employees of the ISO that perform market monitoring and mitigation services for the ISO and the employees of the External Market Monitor that perform market monitoring and mitigation services for the ISO shall execute and shall comply with the terms of the ISO New England Inc. Code of Conduct attached hereto as ***Exhibit 5***.

III.A.18.2. Additional Ethical Conduct Standards.
The employees of the ISO that perform market monitoring and mitigation services for the ISO and the employees of the External Market Monitor that perform market monitoring and mitigation services for the ISO shall also comply with the following additional ethical conduct standards. In the event of a conflict between one or more standards set forth below and one or more standards contained in the ISO New England Inc. Code of Conduct, the more stringent standard(s) shall control.

III.A.18.2.1. Prohibition on Employment with a Market Participant.
No such employee shall serve as an officer, director, employee or partner of a Market Participant.

III.A.18.2.2. Prohibition on Compensation for Services.

No such employee shall be compensated, other than by the ISO or, in the case of employees of the External Market Monitor, by the External Market Monitor, for any expert witness testimony or other commercial services, either to the ISO or to any other party, in connection with any legal or regulatory proceeding or commercial transaction relating to the ISO or the New England Markets.

III.A.18.2.3. Additional Standards Applicable to External Market Monitor.

In addition to the standards referenced in the remainder of this Section 18 of ***Appendix A***, the employees of the External Market Monitor that perform market monitoring and mitigation services for the ISO are subject to conduct standards set forth in the External Market Monitor Services Agreement entered into between the External Market Monitor and the ISO, as amended from time-to-time. In the event of a conflict between one or more standards set forth in the External Market Monitor Services Agreement and one or more standards set forth above or in the ISO New England Inc. Code of Conduct, the more stringent standard(s) shall control.

III.A.19. Protocols on Referral to the Commission of Suspected Violations.

(A) The Internal Market Monitor or External Market Monitor is to make a non-public referral to the Commission in all instances where the Internal Market Monitor or External Market Monitor has reason to believe that a Market Violation has occurred. While the Internal Market Monitor or External Market Monitor need not be able to prove that a Market Violation has occurred, the Internal Market Monitor or External Market Monitor is to provide sufficient credible information to warrant further investigation by the Commission. Once the Internal Market Monitor or External Market Monitor has obtained sufficient credible information to warrant referral to the Commission, the Internal Market Monitor or External Market Monitor is to immediately refer the matter to the Commission and desist from independent action related to the alleged Market Violation. This does not preclude the Internal Market Monitor or External Market Monitor from continuing to monitor for any repeated instances of the activity by the same or other entities, which would constitute new Market Violations. The Internal Market Monitor or External Market Monitor is to respond to requests from the Commission for any additional information in connection with the alleged Market Violation it has referred.

(B) All referrals to the Commission of alleged Market Violations are to be in writing, whether transmitted electronically, by fax, mail or courier. The Internal Market Monitor or External Market Monitor may alert the Commission orally in advance of the written referral.

(C) The referral is to be addressed to the Commission's Director of the Office of Enforcement, with a copy also directed to both the Director of the Office of Energy Market Regulation and the General Counsel.

(D) The referral is to include, but need not be limited to, the following information

(1) The name(s) of and, if possible, the contact information for, the entity(ies) that allegedly took the action(s) that constituted the alleged Market Violation(s);

(2) The date(s) or time period during which the alleged Market Violation(s) occurred and whether the alleged wrongful conduct is ongoing;

(3) The specific rule or regulation, and/or tariff provision, that was allegedly violated, or the nature of any inappropriate dispatch that may have occurred;

(4) The specific act(s) or conduct that allegedly constituted the Market Violation;

(5) The consequences to the market resulting from the acts or conduct, including, if known, an estimate of economic impact on the market;

(6) If the Internal Market Monitor or External Market Monitor believes that the act(s) or conduct constituted a violation of the anti-manipulation rule of Part 1c of the Commission's Rules and Regulations, 18 C.F.R. Part 1c, a description of the alleged manipulative effect on market prices, market conditions, or market rules;

(7) Any other information the Internal Market Monitor or External Market Monitor believes is relevant and may be helpful to the Commission.

(E) Following a referral to the Commission, the Internal Market Monitor or External Market Monitor is to continue to notify and inform the Commission of any information that the Internal Market Monitor or External Market Monitor learns of that may be related to the referral, but the Internal Market Monitor or External Market Monitor is not to undertake any investigative steps regarding the referral except at the express direction of the Commission or Commission staff.

III.A.20. Protocol on Referrals to the Commission of Perceived Market Design Flaws and Recommended Tariff Changes.

(A) The Internal Market Monitor or External Market Monitor is to make a referral to the Commission in all instances where the Internal Market Monitor or External Market Monitor has reason to believe market design flaws exist that it believes could effectively be remedied by rule or tariff changes. The Internal Market Monitor or External Market Monitor must limit distribution of its identifications and recommendations to the ISO and to the Commission in the event it believes broader dissemination could lead to exploitation, with an explanation of why further dissemination should be avoided at that time.

(B) All referrals to the Commission relating to perceived market design flaws and recommended tariff changes are to be in writing, whether transmitted electronically, by fax, mail, or courier. The Internal Market Monitor or External Market Monitor may alert the Commission orally in advance of the written referral.

(C) The referral should be addressed to the Commission's Director of the Office of Energy Market Regulation, with copies directed to both the Director of the Office of Enforcement and the General Counsel.

(D) The referral is to include, but need not be limited to, the following information.

(1) A detailed narrative describing the perceived market design flaw(s);

(2) The consequences of the perceived market design flaw(s), including, if known, an estimate of economic impact on the market;

(3) The rule or tariff change(s) that the Internal Market Monitor or External Market Monitor believes could remedy the perceived market design flaw;

(4) Any other information the Internal Market Monitor or External Market Monitor believes is relevant and may be helpful to the Commission.

(E) Following a referral to the Commission, the Internal Market Monitor or External Market Monitor is to continue to notify and inform the Commission of any additional information regarding the perceived market design flaw, its effects on the market, any additional or modified observations concerning the rule or tariff changes that could remedy the perceived design flaw, any recommendations made by the Internal Market Monitor or External Market Monitor to the regional transmission organization or independent system operator, stakeholders, market participants or state commissions regarding the perceived design flaw, and any actions taken by the regional transmission organization or independent system operator regarding the perceived design flaw.

III.A.21. Review of Offers From New Resources in the Forward Capacity Market.

The Internal Market Monitor shall review offers from new resources in the Forward Capacity Auction as described in this Section III.A.21.

III.A.21.1. Offer Review Trigger Prices.

For each new technology type, the Internal Market Monitor shall establish an Offer Review Trigger Price. Offers in the Forward Capacity Auction at prices that are equal to or above the relevant Offer Review Trigger Price will not be subject to further review by the Internal Market Monitor. A request to submit offers in the Forward Capacity Auction at prices that are below the relevant Offer Review Trigger Price must be submitted in advance of the Forward Capacity Auction as described in Sections III.13.1.1.2.2.3,

III.13.1.3.5 or III.13.1.4.1.1.2.8 and shall be reviewed by the Internal Market Monitor as described in this Section III.A.21.

III.A.21.1.1. Offer Review Trigger Prices for the Forward Capacity Auction.

For resources other than New Import Capacity Resources, the Offer Review Trigger Prices for the twelfth Forward Capacity Auction (for the Capacity Commitment Period beginning on June 1, 2021) shall be as follows:

Generating Capacity Resources	
Technology Type	**Offer Review Trigger Price ($/kW-month)**
combustion turbine	$6.503
combined cycle gas turbine	$7.856
on-shore wind	$11.025

Demand Capacity Resources - Commercial and Industrial	
Technology Type	**Offer Review Trigger Price ($/kW-month)**
Load Management and/or previously installed Distributed Generation	$1.008
new Distributed Generation	based on generation technology type
Energy Efficiency	$0.000

Demand Capacity Resources – Residential	
Technology Type	**Offer Review Trigger Price ($/kW-month)**
Load Management	$7.559
previously installed Distributed Generation	$1.008
new Distributed Generation	based on generation technology type
Energy Efficiency	$0.000

Other Resources	
All other technology types	Forward Capacity Auction Starting Price

Where a new resource is composed of assets having different technology types, the resource's Offer Review Trigger Price will be calculated in accordance with the weighted average formula in Section III.A.21.2(c).

For purposes of determining the Offer Review Trigger Price of a Demand Capacity Resource composed in whole or in part of Distributed Generation, the Distributed Generation is considered new, rather than previously installed, if (1) the Project Sponsor for the New Demand Capacity Resource has participated materially in the development, installation or funding of the Distributed Generation during the five years prior to commencement of the Capacity Commitment Period for which the resource is being qualified for participation, and (2) the Distributed Generation has not been assigned to a Demand Capacity Resource with a Capacity Supply Obligation in a prior Capacity Commitment Period.

For a New Import Capacity Resource that is backed by a single new External Resource and that is associated with an investment in transmission that increases New England's import capability, the Offer Review Trigger Prices in the table above shall apply, based on the technology type of the External Resource; provided that, if a New Import Capacity Resource is associated with an Elective Transmission Upgrade, it shall have an Offer Review Trigger Price of the Forward Capacity Auction Starting Price plus $0.01/kW-month.

For any other New Import Capacity Resource, the Offer Review Trigger Price shall be the Forward Capacity Auction Starting Price plus $0.01/kW-month.

III.A.21.1.2. Calculation of Offer Review Trigger Prices.

(a) The Offer Review Trigger Price for each of the technology types listed above shall be recalculated using updated data for the Capacity Commitment Period beginning on June 1, 2025 and no less often than once every three years thereafter. Where any Offer Review Trigger Price is recalculated, the Internal Market Monitor will review the results of the recalculation with stakeholders and the new Offer Review Trigger Price shall be filed with the Commission prior to the Forward Capacity Auction in which the Offer Review Trigger Price is to apply.

(b) For New Generating Capacity Resources, the methodology used to recalculate the Offer Review Trigger Price pursuant to subsection (a) above is as follows. Capital costs, expected non-capacity revenues and operating costs, assumptions regarding depreciation, taxes and discount rate are input into a capital budgeting model which is used to calculate the break-even contribution required from the Forward

Capacity Market to yield a discounted cash flow with a net present value of zero for the project. The Offer Review Trigger Price is set equal to the year-one capacity price output from the model. The model looks at 20 years of real-dollar cash flows discounted at a rate (Weighted Average Cost of Capital) consistent with that expected of a project whose output is under contract (i.e., a contract negotiated at arm's length between two unrelated parties).

(c) For New Demand Capacity Resources comprised of Energy Efficiency, the methodology used to recalculate the Offer Review Trigger Price pursuant to subsection (a) above shall be the same as that used for New Generating Capacity Resources, with the following exceptions. First, the model takes account of all costs incurred by the utility and end-use customer to deploy the efficiency measure. Second, rather than energy revenues, the model recognizes end-use customer savings associated with the efficiency programs. Third, the model assumes that all costs are expensed as incurred. Fourth, the benefits realized by end-use customers are assumed to have no tax implications for the utility. Fifth, the model discounts cash flows over the Measure Life of the energy efficiency measure.

(d) For New Demand Capacity Resources other than Demand Capacity Resources comprised of Energy Efficiency, the methodology used to recalculate the Offer Review Trigger Price pursuant to subsection (a) above is the same as that used for New Generating Capacity Resources, except that the model discounts cash flows over the contract life. For Demand Capacity Resources (other than those comprised of Energy Efficiency) that are composed primarily of large commercial or industrial customers that use pre-existing equipment or strategies, incremental costs include new equipment costs and annual operating costs such as customer incentives and sales representative commissions. For Demand Capacity Resources (other than Demand Capacity Resources comprised of Energy Efficiency) primarily composed of residential or small commercial customers that do not use pre-existing equipment or strategies, incremental costs include equipment costs, customer incentives, marketing, sales, and recruitment costs, operations and maintenance costs, and software and network infrastructure costs.

(e) For years in which no full recalculation is performed pursuant to subsection (a) above, the Offer Review Trigger Prices will be adjusted as follows:

(1) Each line item associated with capital costs that is included in the capital budgeting model will be associated with the indices included in the table below:

Cost Component	**Index**
gas turbines	BLS-PPI "Turbines and Turbine Generator Sets"

steam turbines	BLS-PPI "Turbines and Turbine Generator Sets"
wind turbines	Bloomberg Wind Turbine Price Index
Other Equipment	BLS-PPI "General Purpose Machinery and Equipment"
construction labor	BLS "Quarterly Census of Employment and Wages" 2371 Utility System Construction Average Annual Pay: − Combustion turbine and combined cycle gas turbine costs to be indexed to values corresponding to the location of Hampden County, Massachusetts − On-shore wind costs to be indexed to values corresponding to the location of Cumberland County, Maine
other labor	BLS "Quarterly Census of Employment and Wages" 2211 Power Generation and Supply Average Annual Pay: − Combustion turbine and combined cycle gas turbine costs to be indexed to values corresponding to the location of Hampden County, Massachusetts − On-shore wind costs to be indexed to values corresponding to the location of Cumberland County, Maine
materials	BLS-PPI "Materials and Components for Construction"
electric interconnection	BLS - PPI "Electric Power Transmission, Control, and Distribution"
gas interconnection	BLS - PPI "Natural Gas Distribution: Delivered to ultimate consumers for the account of others (transportation only)"
fuel inventories	Federal Reserve Bank of St. Louis "Gross Domestic Product: Implicit Price Deflator (GDPDEF)"

(2) Each line item associated with fixed operating and maintenance costs that is included in the capital budgeting model will be associated with the indices included in the table below:

Cost Component	**Index**
labor, administrative and general	BLS "Quarterly Census of Employment and Wages" 2211 Power Generation and Supply Average Annual Pay: − Combustion turbine and combined cycle gas turbine costs to be indexed to values corresponding to the location of Hampden County, Massachusetts − On-shore wind costs to be indexed to values corresponding to the location of Cumberland County, Maine
materials and contract services	BLS-PPI "Materials and Components for Construction"
site leasing costs	Federal Reserve Bank of St. Louis "Gross Domestic Product: Implicit Price Deflator (GDPDEF)"

(3) For each line item in (1) and (2) above, the ISO shall calculate a multiplier that is equal to the average of values published during the most recent 12 month period available at the time of making the adjustment divided by the average of the most recent 12 month period available at the time of establishing the Offer Review Trigger Prices for the FCA reflected in the table in Section III.A.21.1.1 above. The value of each line item associated with capital costs and fixed operating and maintenance costs included

in the capital budgeting model for the FCA reflected in the table in Section A.21.1.1 above will be adjusted by the relevant multiplier.

(4) The energy and ancillary services offset values for each technology type in the capital budgeting model shall be adjusted by inputting to the capital budgeting model the most recent Henry Hub natural gas futures prices, the Algonquin Citygates Basis natural gas futures prices and the Massachusetts Hub On-Peak electricity prices for the months in the Capacity Commitment Period beginning June 1, 2021, as published by ICE.

(5) Renewable energy credit values in the capital budgeting model shall be updated based on the most recent MA Class 1 REC price for the vintage closest to the first year of the Capacity Commitment Period associated with the relevant FCA as published by SNL Financial.

(6) The capital budgeting model and the Offer Review Trigger Prices adjusted pursuant to this subsection (e) will be published on the ISO's web site.

(7) If any of the values required for the calculations described in this subsection (e) are unavailable, then comparable values, prices or sources shall be used.

III.A.21.2. New Resource Offer Floor Prices and Offer Prices.

For every new resource participating in a Forward Capacity Auction, the Internal Market Monitor shall determine a New Resource Offer Floor Price or offer prices, as described in this Section III.A.21.2.

(a) For a Lead Market Participant with a New Capacity Resource that does not submit a request to submit offers in the Forward Capacity Auction at prices that are below the relevant Offer Review Trigger Price as described in Sections III.13.1.1.2.2.3, III.13.1.3.5 or III.13.1.4.1.1.2.8, the New Resource Offer Floor Price shall be calculated as follows:

> For a New Import Capacity Resource (other than a New Import Capacity Resource that is (i) backed by a single new External Resource and that is associated with an investment in transmission that increases New England's import capability or (ii) associated with an Elective Transmission Upgrade) the New Resource Offer Floor Price shall be $0.00/kW-month.

For a New Generating Capacity Resource, New Import Capacity Resource that is backed by a single new External Resource and that is associated with an investment in transmission that increases New England's import capability, New Import Capacity Resource that is associated with an Elective Transmission Upgrade, and New Demand Capacity Resource, the New Resource Offer Floor Price shall be equal to the applicable Offer Review Trigger Price.

A resource having a New Resource Offer Floor Price higher than the Forward Capacity Auction Starting Price shall not be included in the Forward Capacity Auction.

(b) For a Lead Market Participant with a New Capacity Resource that does submit a request to submit offers in the Forward Capacity Auction at prices that are below the relevant Offer Review Trigger Price as described in Sections III.13.1.1.2.2.3, III.13.1.3.5 and III.13.1.4.1.1.2.8, the resource's New Resource Offer Floor Price and offer prices in the case of a New Import Capacity Resource (other than a New Import Capacity Resource that is backed by a single new External Resource and that is associated with an investment in transmission that increases New England's import capability or a New Import Capacity Resource that is associated with an Elective Transmission Upgrade) shall be calculated as follows:

For a New Import Capacity Resource that is subject to the pivotal supplier test in Section III.A.23 and is found not to be associated with a pivotal supplier as determined pursuant to Section III.A.23, the resource's New Resource Offer Floor Price and offer prices shall be equal to the lower of (i) the requested offer price submitted to the ISO as described in Sections III.13.1.1.2.2.3 and III.13.1.3.5; or (ii) the price revised pursuant to Section III.13.1.3.5.7.

For any other New Capacity Resource, the Internal Market Monitor shall enter all relevant resource costs and non-capacity revenue data, as well as assumptions regarding depreciation, taxes, and discount rate into the capital budgeting model used to develop the relevant Offer Review Trigger Price and shall calculate the break-even contribution required from the Forward Capacity Market to yield a discounted cash flow with a net present value of zero for the project. The Internal Market Monitor shall compare the requested offer price to this capacity price estimate and the resource's New Resource Offer Floor Price and offer prices shall be determined as follows:

(i) The Internal Market Monitor will exclude any out-of-market revenue sources from the cash flows used to evaluate the requested offer price. Out-of-market revenues are any revenues that are: (a) not tradable throughout the New England Control Area or that are restricted to resources

within a particular state or other geographic sub-region; or (b) not available to all resources of the same physical type within the New England Control Area, regardless of the resource owner. Expected revenues associated with economic development incentives that are offered broadly by state or local government and that are not expressly intended to reduce prices in the Forward Capacity Market are not considered out-of-market revenues for this purpose. In submitting its requested offer price, the Project Sponsor shall indicate whether and which project cash flows are supported by a regulated rate, charge, or other regulated cost recovery mechanism. If the project is supported by a regulated rate, charge, or other regulated cost recovery mechanism, then that rate will be replaced with the Internal Market Monitor estimate of energy revenues. Where possible, the Internal Market Monitor will use like-unit historical production, revenue, and fuel cost data. Where such information is not available (e.g., there is no resource of that type in service), the Internal Market Monitor will use a forecast provided by a credible third party source. The Internal Market Monitor will review capital costs, discount rates, depreciation and tax treatment to ensure that it is consistent with overall market conditions. Any assumptions that are clearly inconsistent with prevailing market conditions will be adjusted.

(ii) For a New Demand Capacity Resource, the resource's costs shall include all expenses, including incentive payments, equipment costs, marketing and selling and administrative and general costs incurred to acquire and/or develop the Demand Capacity Resource. Revenues shall include all non-capacity payments expected from the ISO-administered markets made for services delivered from the associated Demand Response Resource, and expected costs avoided by the associated end-use customer as a direct result of the installation or implementation of the associated Asset(s).

(iii) For a New Capacity Resource that has achieved commercial operation prior to the New Capacity Qualification Deadline for the Forward Capacity Auction in which it seeks to participate, the relevant capital costs to be entered into the capital budgeting model will be the undepreciated original capital costs adjusted for inflation. For any such resource, the prevailing market conditions will be those that were in place at the time of the decision to construct the resource.

(iv) Sufficient documentation and information must be included in the resource's qualification package to allow the Internal Market Monitor to make the determinations described in this subsection (b). Such documentation should include all relevant financial estimates and cost

projections for the project, including the project's pro-forma financing support data. For a New Import Capacity Resource, such documentation should also include the expected costs of purchasing power outside the New England Control Area (including transaction costs and supported by forward power price index values or a power price forecast for the applicable Capacity Commitment Period), expected transmission costs outside the New England Control Area, and expected transmission costs associated with importing to the New England Control Area, and may also include reasonable opportunity costs and risk adjustments. For a new capacity resource that has achieved commercial operation prior to the New Capacity Qualification Deadline, such documentation should also include all relevant financial data of actual incurred capital costs, actual operating costs, and actual revenues since the date of commercial operation. If the supporting documentation and information required by this subsection (b) is deficient, the Internal Market Monitor, at its sole discretion, may consult with the Project Sponsor to gather further information as necessary to complete its analysis. If after consultation, the Project Sponsor does not provide sufficient documentation and information for the Internal Market Monitor to complete its analysis, then the resource's New Resource Offer Floor Price shall be equal to the Offer Review Trigger Price.

(v) If the Internal Market Monitor determines that the requested offer prices are consistent with the Internal Market Monitor's capacity price estimate, then the resource's New Resource Offer Floor Price shall be equal to the requested offer price, subject to the provisions of subsection (vii) concerning New Import Capacity Resources.

(vi) If the Internal Market Monitor determines that the requested offer prices are not consistent with the Internal Market Monitor's capacity price estimate, then the resource's offer prices shall be set to a level that is consistent with the capacity price estimate, as determined by the Internal Market Monitor. Any such determination will be explained in the resource's qualification determination notification and will be filed with the Commission as part of the filing described in Section III.13.8.1(c), subject to the provisions of subsection (vii) concerning New Import Capacity Resources.

(vii) For New Import Capacity Resources that have been found to be associated with a pivotal supplier as determined pursuant to Section III.A.23, if the supplier elects to revise the requested offer prices pursuant to Section III.13.1.3.5.7 to values that are below the Internal Market

Monitor's capacity price estimate established pursuant to subsection (v) or (vi), then the resource's offer prices shall be equal to the revised offer prices.

(c) For a new capacity resource composed of assets having different technology types the Offer Review Trigger Price shall be the weighted average of the Offer Review Trigger Prices of the asset technology types of the assets that comprise the resource, based on the expected capacity contribution from each asset technology type. Sufficient documentation must be included in the resource's qualification package to permit the Internal Market Monitor to determine the weighted average Offer Review Trigger Price.

III.A.22. [Reserved.]

III.A.23. Pivotal Supplier Test for Existing Capacity Resources and New Import Capacity Resources in the Forward Capacity Market.

III.A.23.1. Pivotal Supplier Test.

The pivotal supplier test is performed prior to the commencement of the Forward Capacity Auction at the system level and for each import-constrained Capacity Zone.

An Existing Capacity Resource or New Import Capacity Resource is associated with a pivotal supplier if, after removing all the supplier's FCA Qualified Capacity, the ability to meet the relevant requirement is less than the requirement. Only those New Import Capacity Resources that are not (i) backed by a single new External Resource and associated with an investment in transmission that increases New England's import capability, or (ii) associated with an Elective Transmission Upgrade, are subject to the pivotal supplier test.

For the system level determination, the relevant requirement is the Installed Capacity Requirement (net of HQICCs). For each import-constrained Capacity Zone, the relevant requirement is the Local Sourcing Requirement for that import-constrained Capacity Zone.

At the system level, the ability to meet the relevant requirement is the sum of the following:

(a) The total FCA Qualified Capacity from all Existing Generating Capacity Resources and Existing Demand Capacity Resources in the Rest-of-Pool Capacity Zone;

(b) For each modeled import-constrained Capacity Zone, the greater of:

(1) the total FCA Qualified Capacity from all Existing Generating Capacity Resources and Existing Demand Capacity Resources within the import-constrained Capacity Zone plus, for each modeled external interface connected to the import-constrained Capacity Zone, the lesser of: (i) the capacity transfer limit of the interface (net of tie benefits), and; (ii) the total amount of FCA Qualified Capacity from Import Capacity Resources over the interface, and;

(2) the Local Sourcing Requirement of the import-constrained Capacity Zone;

(c) For each modeled nested export-constrained Capacity Zone, the lesser of:

(1) the total FCA Qualified Capacity from all Existing Generating Capacity Resources and Existing Demand Capacity Resources within the nested export-constrained Capacity Zone plus, for each external interface connected to the nested export-constrained Capacity Zone, the lesser of: (i) the capacity transfer limit of the interface (net of tie benefits), and; (ii) the total amount of FCA Qualified Capacity from Import Capacity Resources over the interface, and;

(2) the Maximum Capacity Limit of the nested export-constrained Capacity Zone;

(d) For each modeled export-constrained Capacity Zone that is not a nested export-constrained Capacity Zone, the lesser of:

(1) the total FCA Qualified Capacity from all Existing Generating Capacity Resources and Existing Demand Capacity Resources within the export-constrained Capacity Zone, excluding the total FCA Qualified Capacity from Existing Generating Capacity Resources and Existing Demand Capacity Resources within a nested export-constrained Capacity Zone, plus, for each external interface connected to the export-constrained Capacity Zone that is not included in any nested export-constrained Capacity Zone, the lesser of: (i) the capacity transfer limit of the interface (net of tie benefits), and; (ii) the total amount of FCA Qualified Capacity from Import Capacity Resources over the interface, excluding the contribution from any nested export-constrained Capacity Zone as determined pursuant to Section III.A.23.1(c), and;

(2) the Maximum Capacity Limit of the export-constrained Capacity Zone minus the contribution from any associated nested export-constrained Capacity Zone as determined pursuant to Section III.A.23.1(c), and;

(e) For each modeled external interface connected to the Rest-of-Pool Capacity Zone, the lesser of:

(1) the capacity transfer limit of the interface (net of tie benefits), and;

(2) the total amount of FCA Qualified Capacity from Import Capacity Resources over the interface.

For each import-constrained Capacity Zone, the ability to meet the relevant requirement is the sum of the following:

(1) The total FCA Qualified Capacity from all Existing Generating Capacity Resources and Existing Demand Capacity Resources located within the import-constrained Capacity Zone; and
(2) For each modeled external interface connected to the import-constrained Capacity Zone, the lesser of: (1) the capacity transfer limit of the interface (net of tie benefits), and; (2) the total amount of FCA Qualified Capacity from Import Capacity Resources over the interface.

III.A.23.2. Conditions Under Which Capacity is Treated as Non-Pivotal.

FCA Qualified Capacity of a supplier that is determined to be pivotal under Section III.A.23.1 is treated as non-pivotal under the following four conditions:

(a) If the removal of a supplier's FCA Qualified Capacity in an export-constrained Capacity Zone or nested export-constrained Capacity Zone does not change the quantity calculated in Section III.A.23.1(c) for that export-constrained Capacity Zone or nested export-constrained Capacity Zone, then that capacity is treated as capacity of a non-pivotal supplier.
(b) If the removal of a supplier's FCA Qualified Capacity in the form of Import Capacity Resources at an external interface does not change the quantity calculated in Section III.A.23.1(d) for that interface, then that capacity is treated as capacity of a non-pivotal supplier.
(c) If the removal of a supplier's FCA Qualified Capacity in the form of Import Capacity Resources at an external interface connected to an import-constrained Capacity Zone does not change the quantity calculated in Section III.A.23.1(f) for that interface, then that capacity is treated as capacity of a non-pivotal supplier.
(d) If a supplier whose only FCA Qualified Capacity is a single capacity resource with a bid that (i) is not subject to rationing under Section III.13.1.2.3.1 or III.13.2.6, and (ii) contains only one price-quantity pair for the entire FCA Qualified Capacity amount, then the capacity of that resource is treated as capacity of a non-pivotal supplier.

III.A.23.3. Pivotal Supplier Test Notification of Results.

Results of the pivotal supplier test will be made available to suppliers no later than seven days prior to the start of the Forward Capacity Auction.

III.A.23.4. Qualified Capacity for Purposes of Pivotal Supplier Test.

For purposes of the tests performed in Sections III.A.23.1 and III.A.23.2, the FCA Qualified Capacity of a supplier includes the capacity of Existing Generating Capacity Resources, Existing Demand Capacity Resources, Existing Import Capacity Resources, and New Import Capacity Resources (other than (i) a New Import Capacity Resource that is backed by a single new External Resource and that is associated with an investment in transmission that increases New England's import capability; and (ii) a New Import Capacity Resource associated with an Elective Transmission Upgrade) that is controlled by the supplier or its Affiliates.

For purposes of determining the ability to meet the relevant requirement under Section III.A.23.1, the FCA Qualified Capacity from New Import Capacity Resources does not include (i) any New Import Capacity Resource that is backed by a single new External Resource and that is associated with an investment in transmission that increases New England's import capability; and (ii) any New Import Capacity Resource associated with an Elective Transmission Upgrade.

For purposes of determining the FCA Qualified Capacity of a supplier or its Affiliates under Section III.A.23.4, "control" or "controlled" means the possession, directly or indirectly, of the authority to direct the decision-making regarding how capacity is offered into the Forward Capacity Market, and includes control by contract with unaffiliated third parties. In complying with Section I.3.5 of the ISO Tariff, a supplier shall inform the ISO of all capacity that it and its Affiliates control under this Section III.A.23.4 and all capacity the control of which it has contracted to a third party.

III.A.24. Retirement Portfolio Test for Existing Capacity Resources in the Forward Capacity Market.

The retirement portfolio test is performed prior to the commencement of the Forward Capacity Auction for each Lead Market Participant submitting a Permanent De-List Bid or Retirement De-List Bid. The test will be performed as follows:

If

i. The annual capacity revenue from the Lead Market Participant's total FCA Qualified Capacity, not including the FCA Qualified Capacity associated with the Permanent De-List Bid or Retirement De-List Bid, is greater than

ii. the annual capacity revenue from the Lead Market Participant's total FCA Qualified Capacity, including the FCA Qualified Capacity associated with the Permanent De-List Bid or Retirement De-List Bid, then

iii. the Lead Market Participant will be found to have a portfolio benefit pursuant to the retirement portfolio test.

Where,

iv. the Lead Market Participant's annual capacity revenue from the Lead Market Participant's total FCA Qualified Capacity not including the FCA Qualified Capacity associated with the Permanent De-List Bid or Retirement De-List Bid is calculated as the product of (a) the Lead Market Participant's total FCA Qualified Capacity not including the FCA Qualified Capacity associated with the Permanent De-List Bid or Retirement De-List Bid and (b) the Internal Market Monitor-estimated capacity clearing price not including the FCA Qualified Capacity associated with the Permanent De-List Bid or Retirement De-List Bid.

v. The Lead Market Participant's annual capacity revenue from the Lead Market Participant's total FCA Qualified Capacity including the FCA Qualified Capacity associated with the Permanent De-List Bid or Retirement De-List Bid is calculated as the product of (a) the Lead Market Participant's total FCA Qualified Capacity including the FCA Qualified Capacity associated with the Permanent De-List Bid or Retirement De-List Bid and (b) the Internal Market Monitor-estimated capacity clearing price including the FCA Qualified Capacity associated with the Permanent De-List Bid or Retirement De-List Bid.

vi. The Internal Market Monitor-estimated capacity clearing price, not to exceed the Forward Capacity Auction Starting Price, is based on the parameters of the System-Wide Capacity Demand Curve and Capacity Zone Demand Curves as specified in Section III.13.2.2.

For purposes of the test performed in this Section III.A.24, the FCA Qualified Capacity of a Lead Market Participant includes the capacity of Existing Capacity Resources that is controlled by the Lead Market Participant or its Affiliates.

For purposes of determining the FCA Qualified Capacity of a Lead Market Participant or its Affiliates under this Section III.A.24, “control” or “controlled” means the possession, directly or indirectly, of the authority to direct the decision-making regarding how capacity is offered into the Forward Capacity Market, and includes control by contract with unaffiliated third parties. In complying with Section I.3.5 of the ISO Tariff, a Lead Market Participant shall inform the ISO of all capacity that it and its Affiliates control under this Section III.A.4 and all capacity the control of which it has contracted to a third party.

APPENDIX K

INVENTORIED ENERGY PROGRAM

III.K Inventoried Energy Program

For the winter of 2023-2024 (the "relevant winter period"), the ISO shall administer an inventoried energy program in accordance with the provisions of this Appendix K.

III.K.1. Submission of Election Information

Participation in the inventoried energy program is voluntary. To participate in both the forward and spot components of the program, the information listed in this Section III.K.1 must be submitted to the ISO no later than the October 1 immediately preceding the start of the relevant winter and must reflect an ability to provide the submitted inventoried energy throughout the relevant winter period. To participate in the spot component of the program only, the information listed in this Section III.K.1 may be submitted to the ISO through the end of the relevant winter period, in which case participation will begin (prospectively only) upon review and approval by the ISO of the information submitted.

(a) A list of the Market Participant's assets that will participate in the inventoried energy program, with a description for each such asset of: the Market Participant's Ownership Share in the asset; the types of fuel it can use; the approximate maximum amount of each fuel type that can be stored on site (and in upstream ponds) or, in the case of natural gas, the amount that is subject to a contract meeting the requirements described in Section III.K.1(a)(iii), as measured pursuant to the provisions of Section III.K.3.2.1.1(a); and a list of other assets at the same facility that share the fuel inventory (or, in the case of natural gas, a list of assets at the same or any other facility that can also take fuel pursuant to the same contract).

(i) The following asset types may not be included in a Market Participant's list of assets: Settlement Only Resources; assets not located in the New England Control Area; assets being compensated pursuant to a cost-of-service agreement (as described in Section III.13.2.5.2.5) during the relevant winter period; and assets that cannot operate on stored fuel (or natural gas subject to a contract as described in Section III.K.1(a)(iii)) at the ISO's direction.

(ii) A Demand Response Resource with Distributed Generation may be included in a Market Participant's list of assets.

(iii) For any asset listed that will participate in the inventoried energy program using natural gas as a fuel type, the Market Participant must also submit an executed contract for firm delivery of natural gas. Any such contract must include no limitations on when natural gas can be called during a day, and must specify the parties to the contract, the volume of gas to be delivered, the price to be paid for that gas, the pipeline delivery point name and gas meter number of the listed asset, terms related to pipeline transportation to the meter of the listed asset (with indication of whether the gas supplier or another entity is providing the transportation), and all other terms, conditions, or related agreements affecting whether and when gas will be delivered, the volume of gas to be delivered, and the price to be paid for that gas.

(b) A detailed description of how the Market Participant's energy inventory will be measured after each Inventoried Energy Day in accordance with the provisions of Section III.K.3.2.1.1 and converted to MWh (including the rates at which fuel is converted to energy for each asset). Where assets share fuel inventory, if the Market Participant believes that fuel should be allocated among those assets in a manner other than the default approach described in Section III.K.3.2.1.1(e)(ii), this description should explain and support that alternate allocation.

(c) Whether the Market Participant is electing to participate in only the spot component of the inventoried energy program or in both the forward and spot components.

(d) If electing to participate in both the forward and spot components of the program, the total MWh value for which the Market Participant elects to be compensated at the forward rate (the "Forward Energy Inventory Election"). This MWh value must be less than or equal to the combined MW output that the assets listed by the Market Participant (adjusted to account for Ownership Share) could provide over a period of 72 hours, as limited by the maximum amount of each fuel type that can be stored on site (and in upstream ponds) for each asset and as limited by the terms of any natural gas contracts submitted pursuant to Section III.K.1(a)(iii). If the Market Participant is submitting one or more contracts for natural gas, the Market Participant must indicate whether any of the suppliers listed in those contracts have the capability to deliver vaporized liquefied natural gas to New England, and if so, what portion of its Forward Energy Inventory Election, in MWh, should be attributed to liquefied natural gas (the "Forward LNG Inventory Election"). (For Market Participants electing to participate in only the spot component of the program, the Forward Energy Inventory Election and Forward LNG Inventory Election shall be zero.)

III.K.1.1 ISO Review and Approval of Election Information

The ISO will review each Market Participant's election submission, and may confer with the Market Participant to clarify or supplement the information provided. The ISO shall modify the amounts as necessary to ensure consistency with asset-specific operational characteristics, terms and conditions associated with submitted contracts, regulatory restrictions, and the requirements of the inventoried energy program. For election information that is submitted no later than October 1, the ISO will report the final program participation values to the Market Participant by the November 1 immediately preceding the start of the relevant winter, and participation will begin on December 1. For election information that is submitted after October 1 (spot component participation only), the ISO will, as soon as practicable, report the final program participation values and the date that participation will begin to the Market Participant.

(a) In performing this review, the ISO shall reject all or any portions of a contract for natural gas that:

(i) does not meet the requirements of Section III.K.1(a)(iii); or

(ii) requires (except in the case of an asset that is supplied from a liquefied natural gas facility adjacent and directly connected to the asset) the Market Participant to incur incremental costs to exercise the contract that may be greater than 250 percent of the average of the sum of the monthly Henry Hub natural gas futures prices and the Algonquin Citygates Basis natural gas futures prices for the December, January, and February of the relevant winter period on the earlier of the day the contract is executed and the first Business Day in October prior to that winter period.

(b) In performing this review, if the total of the Forward LNG Inventory Elections from all participating Market Participants (excluding amounts to be supplied to an asset from a liquefied natural gas facility adjacent and directly connected to the asset) exceeds 560,000 MWh, the ISO shall prorate each such Forward LNG Inventory Election such that the sum of such Forward LNG Inventory Elections is no greater than 560,000 MWh, and each Market Participant's Forward Energy Inventory Election shall be adjusted accordingly.

III.K.1.2 Posting of Forward Energy Inventory Election Amount

As soon as practicable after the November 1 immediately preceding the start of the relevant winter, the ISO will post to its website the total amount of Forward Energy Inventory Elections and Forward LNG Inventory Elections participating in the inventoried energy program for that winter.

III.K.2 Inventoried Energy Base Payments

A Market Participant participating in the forward and spot components of the inventoried energy program shall receive a base payment for each day of the months of December, January, and February. Each such base payment shall be equal to the Market Participant's Forward Energy Inventory Election (adjusted as described in Section III.K.1.1) multiplied by $82.49 per MWh and divided by the total number of days in those three months.

III.K.3 Inventoried Energy Spot Payments

A Market Participant participating in the spot component of the inventoried energy program (whether or not the Market Participant is also participating in the forward component of the program) shall receive a spot payment for each Inventoried Energy Day as calculated pursuant to this Section III.K.3.

III.K.3.1 Definition of Inventoried Energy Day

An Inventoried Energy Day shall exist for any Operating Day that occurs in the months of December, January, or February and for which the average of the high temperature and the low temperature on that Operating Day, as measured and reported by the National Weather Service at Bradley International Airport in Windsor Locks, Connecticut, is less than or equal to 17 degrees Fahrenheit.

III.K.3.2 Calculation of Inventoried Energy Spot Payment

A Market Participant's spot payment for an Inventoried Energy Day, which may be positive or negative, shall equal the Market Participant's Real-Time Energy Inventory minus its Forward Energy Inventory Election, with the difference multiplied by $8.25 per MWh.

III.K.3.2.1 Calculation of Real-Time Energy Inventory

A Market Participant's Real-Time Energy Inventory for an Inventoried Energy Day shall be the sum of the Real-Time Energy Inventories for each of the Market Participant's assets participating in the program (adjusted as described in Section III.K.3.2.1.2); provided, however, that where more than one Market Participant has an Ownership Share in an asset, the asset's Real-Time Energy Inventory will be apportioned based on each Market Participant's Ownership Share.

III.K.3.2.1.1 Asset-Level Real-Time Energy Inventory

Each asset's Real-Time Energy Inventory will be determined as follows:

(a) The Market Participant must measure and report to the ISO the Real-Time Energy Inventory for each of the assets participating in the program between 7:00 a.m. and 8:00 a.m. on the Operating Day immediately following each Inventoried Energy Day. The Real-Time Energy Inventory must be reported to the ISO both in MWh and in units appropriate to the fuel type and measured in accordance with the following provisions:

(i) Oil. The Real-Time Energy Inventory of an asset that runs on oil shall be the number of dedicated barrels of oil stored in an in-service tank (located on site or at an adjacent location with direct pipeline transfer capability to the asset), excluding any amount that is unobtainable or unusable (due to priming requirements, sediment, volume below the suction line, or any other reason).

(ii) Coal. The Real-Time Energy Inventory of an asset that runs on coal shall be the number of metric tons of coal stored on site, excluding any amount that is unobtainable or unusable for any reason.

(iii) Nuclear. The Real-Time Energy Inventory of a nuclear asset shall be the number of days until the asset's next scheduled refueling outage.

(iv) Natural Gas. The Real-Time Energy Inventory for an asset that runs on natural gas shall be the amount of natural gas available to the asset pursuant to the terms of the relevant contracts submitted pursuant to Section III.K.1(a)(iii), adjusted to reflect any limitation that the suppliers listed in the contracts may have on the capability to deliver natural gas. The Market Participant must specify what portion of the asset's Real-Time Energy Inventory, in MWh, is associated with liquefied natural gas.

(v) Pumped Hydro. The Real-Time Energy Inventory of a pumped storage asset shall be the amount of water (in gallons or by elevation, consistent with the description provided by the Market Participant pursuant to Section III.K.1(b)) in the on-site reservoir that is available for generation, excluding any amount that is unobtainable or unusable for any reason.

(vi) Pondage. The Real-Time Energy Inventory of an asset with pondage shall be the amount of water (in gallons or by elevation, consistent with the description provided by the Market Participant pursuant to Section III.K.1(b)) in on-site and upstream ponds controlled by the Market Participant with a transit time to the asset of no more than 12 hours, excluding any amount that is unobtainable or unusable for any reason.

(vii) Biomass/Refuse. The Real-Time Energy Inventory of an asset that runs on biomass or refuse shall be the number of metric tons of the relevant material stored on site, excluding any amount that is unobtainable or unusable for any reason.

(viii) Electric Storage Facility. The Real-Time Energy Inventory of an Electric Storage Facility shall be its available energy in MWh.

(b) If the Market Participant fails to measure or report the energy inventory or fuel amounts for an asset as required, that asset's Real-Time Energy Inventory for the Inventoried Energy Day shall be zero.

(c) The Market Participant must limit each asset's Real-Time Energy Inventory as appropriate to respect federal and state restrictions on the use of the fuel (such as water flow or emissions limitations).

(d) The reported amounts are subject to verification by the ISO. As part of any such verification, the ISO may request additional information or documentation from a Market Participant, or may require a certificate signed by a Senior Officer of the Market Participant attesting that the reported amount of fuel is available to the Market Participant as required by the provisions of the inventoried energy program.

(e) In determining final Real-Time Energy Inventory amounts for each asset, the ISO will:

(i) adjust the reported amounts consistent with the results of any verification performed pursuant to Section III.K.3.2.1.1(d);

(ii) allocate shared fuel inventory among the relevant assets in a manner that maximizes its use based on the efficiency with which the assets convert fuel to energy (unless

information submitted pursuant to Section III.K.1(b) supports a different allocation) and that is consistent with any applicable contract provisions (in the case of natural gas) and maximum daily production limits of the assets sharing fuel inventory; and

(iii) limit each asset's Real-Time Energy Inventory to the asset's average available outage-adjusted output on the Inventoried Energy Day for a maximum duration of 72 hours.

III.K.3.2.1.2 Proration of Liquefied Natural Gas

If the total amount of Real-Time Energy Inventory associated with liquefied natural gas (excluding amounts to be supplied to an asset from a liquefied natural gas facility adjacent and directly connected to the asset) exceeds 560,000 MWh, then the ISO shall prorate such Real-Time Energy Inventory associated with liquefied natural gas as follows:

(a) any Real-Time Energy Inventory associated with liquefied natural gas that corresponds to a Market Participant's Forward LNG Inventory Election (prorated as described in Section III.K.1.1(b)) shall be counted without reduction; and

(b) any Real-Time Energy Inventory associated with liquefied natural gas that does not correspond to a Market Participant's Forward LNG Inventory Election (prorated as described in Section III.K.1.1(b)) shall be prorated such that the sum of the Real-Time Energy Inventory associated with liquefied natural gas (including the amount described in Section III.K.3.2.1.2(a)) does not exceed 560,000 MWh.

III.K.4 Cost Allocation

Costs associated with the inventoried energy program shall be allocated on a regional basis to Real-Time Load Obligation, excluding Real-Time Load Obligation associated with Storage DARDs and Real-Time Load Obligation associated with Coordinated External Transactions. Costs associated with base payments shall be allocated across all days of the months of December, January, and February; costs associated with spot payments shall be allocated to the relevant Inventoried Energy Day.

SECTION III

MARKET RULE 1

APPENDIX L

ISO NEW ENGLAND FUEL SECURITY RELIABILITY REVIEW STANDARD

As described in Section III.13.2.5.2.5A, a fuel security reliability review will be performed for certain submissions by Existing Generating Capacity Resources. This Appendix establishes the reliability trigger for that fuel security reliability review. This Appendix L will remain in effect for the 2022/23 and 2023/24 Capacity Commitment Periods, after which this Appendix L will sunset.

The fuel security model used for reliability reviews shall consist of an hour-by-hour chronological simulation of the electric supply for the winter period from the beginning of December through the end of February. As applied to the fuel security reliability review model established pursuant to Appendix I of Planning Procedure No. 10, observation of either of the following will result in the generator being tested having its (i) Retirement De-List Bids, (ii) substitution auction demand bids, and (iii) certain bilateral transactions and reconfiguration auction demand bid offers rejected for reliability reasons:

(i) The retirement will result in the depletion of 10-minute reserves below 700 MW in any hour in the absence of a contingency in more than one liquefied natural gas supply scenario case or,

(ii) the use of load shedding in any hour pursuant to Operating Procedure No. 7.

Attachment F

Governors List

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