October 31, 2023

VIA ELECTRONIC FILING

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

Re: Revisions to ISO New England Transmission, Markets and Services Tariff to Establish a Jointly Optimized Day-Ahead Market for Energy and Ancillary Services, Docket No. ER24- -000

REQUEST FOR ORDER IN 90 DAYS

Dear Secretary Bose:

Pursuant to Section 205 of the Federal Power Act,[1] ISO New England Inc. (the "ISO"), joined by the New England Power Pool ("NEPOOL") Participants Committee[2] (together, the "Filing Parties"),[3] hereby electronically submits revisions to the ISO New England Inc. Transmission, Markets and Services Tariff (the "Tariff"). As more fully described in Sections III through IX of this transmittal letter, the ISO proposes to revise Section I.2.2, Market Rule 1, and Appendix A to Market Rule 1 of the Tariff to establish a jointly optimized Day-Ahead market (hereinafter "Day-Ahead Market") for energy and ancillary services. This proposal, referred to by the ISO as the Day-Ahead Ancillary Services Initiative ("DASI") is supported by the Testimony of Dr. Matthew White (the "White Testimony"), the Testimony of Benjamin Ewing

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[1] 16 U.S.C. § 824d.

[2] Capitalized terms used but not otherwise defined in this filing have the meanings ascribed thereto in the ISO New England Transmission, Markets and Services Tariff (the "Tariff"), the Second Restated NEPOOL Agreement, the Participants Agreement, and, as applicable, the Glossary of Terms Used in NERC Reliability Standards.

[3] Under New England's Regional Transmission Organization arrangements, the rights to make this filing of revisions to the Tariff under Section 205 of the Federal Power Act belong to the ISO. NEPOOL, which pursuant to the Participants Agreement provides the sole Participant Processes for advisory voting on ISO matters, supported the revisions reflected in this filing and, accordingly, joins in this Section 205 filing.

(the "Ewing Testimony"), and the Testimony of Dr. Parviz Alivand (the "Alivand Testimony"),[4] which are sponsored solely by the ISO.

As addressed in Section XI of this transmittal letter, the ISO respectfully requests an effective date of March 1, 2025, and that the Federal Energy Regulatory Commission (the "Commission") issue an order accepting these Tariff revisions no later than ninety (90) days from the date of this filing, in order to allow the ISO time to implement the proposed Day-Ahead Market.

I. DESCRIPTION OF THE FILING PARTIES AND COMMUNICATIONS

The ISO is the private, non-profit entity that serves as the Regional Transmission Organization for New England. The ISO operates the New England bulk power system and administers New England's organized wholesale electricity market pursuant to the Tariff and the Transmission Operating Agreement with the New England Participating Transmission Owners. In its capacity as a Regional Transmission Organization, the ISO has the responsibility to protect the short-term reliability of the New England Control Area and to operate the system according to reliability standards established by the Northeast Power Coordinating Council ("NPCC") and the North American Electric Reliability Corporation ("NERC").

The signatories to the New England Power Pool Agreement, which was first entered into in 1971, are referred to collectively as "NEPOOL." Currently, there are more than 520 signatories, referred to either as "Participants" or "members." Participants include all of the electric utilities rendering or receiving services under the Tariff, as well as independent power generators, marketers, load aggregators, brokers, consumer-owned utility systems, demand response providers (including owners of distributed generation and aggregators of such generation), developers, end users, and merchant transmission providers. Pursuant to revised governance provisions the Commission accepted in *ISO New England Inc., et al.*, 109 FERC ¶ 61,147 (2004), the Participants act through the NEPOOL Participants Committee. Section 6.1 of the Second Restated NEPOOL Agreement and Section 8.1.3(c) of the Participants Agreement authorize the Participants Committee to represent NEPOOL in proceedings before the Commission. Through the Commission-approved Participant Processes, NEPOOL is the vehicle through which all stakeholders with business interests in New England are able to provide informed input and advice to the ISO.

Correspondence and communications in this proceeding should be addressed to the following:

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[4] Matthew White is the ISO's Vice President, Market Development and Settlements and Chief Economist. Benjamin Ewing is a Principal Analyst, and Parviz Alivand is Manager, Market Design and Principal Economist, in the ISO's Market Development department.

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II. STANDARD OF REVIEW

The Filing Parties submit the Tariff revisions proposed as part of DASI pursuant to Section 205 of the Federal Power Act, which "gives a utility the right to file rates and terms for services rendered with its assets."[6] Under Section 205, the Commission "plays 'an essentially passive and reactive' role"[7] whereby it "can reject [a filing] only if it finds that the changes proposed by the public utility are not 'just and reasonable.'"[8] The Commission limits this inquiry "into whether the rates proposed by a utility are reasonable – and [this inquiry does not]

[5] Due to the joint nature of this filing, the Filing Parties respectfully request a waiver of Section 385.203(b)(3) of the Commission's regulations to allow the inclusion of more than two persons on the service list in this proceeding.

[6] *Atlantic City Elec. Co. v. FERC*, 295 F.3d 1, 9 (D.C. Cir. 2002).

[7] *Id.* at 10 (quoting *City of Winnfield v. FERC*, 744 F.2d 871, 876 (D.C. Cir. 1984)).

[8] *Id.* at 9.

extend to determining whether a proposed rate schedule is more or less reasonable than alternative rate designs."[9] The revisions filed herein "need not be the only reasonable methodology, or even the most accurate."[10] As a result, even if an intervenor or the Commission develops an alternate proposal, the Commission must accept this Section 205 filing if it is just and reasonable.[11]

III. EXECUTIVE SUMMARY AND CONTEXT FOR PROPOSAL

The ISO, as part of its responsibility to ensure reliable operation of the New England bulk electric system, must identify the resources that are able to provide the energy and reserves necessary to meet the region's load forecast and reserve needs for the Operating Day. This process includes the development of a next-day Operating Plan, whereby the ISO identifies Day-Ahead the resources that can provide these services during the Operating Day (*i.e.*, in Real-Time).[12] Today, the ISO relies on non-market processes to identify the resources that will be available next-day to provide reserves in Real-Time, and to identify the resources available to satisfy the load forecast whenever the load forecast exceeds the amount of physical energy cleared in the Day-Ahead Energy Market (referred to by the ISO as the Day-Ahead "energy gap"). This process results in both (1) under-compensation to those resources identified to provide these capabilities during the Operating Day and (2) no specific financial obligation or incentive for such resources to be prepared to perform in Real-Time in accordance with the Operating Plan.[13]

Addressing these two concerns is a priority for the ISO because the resources on which the region regularly relies to formulate the next-day Operating Plan are those with the fast-ramping and fast-starting reliability attributes the region needs as it heads into a future with greater uncertainty. As the Commission is aware, New England's power system and resource mix are in transition, as are the weather patterns that will affect New England's power system.[14]

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[9] *Cities of Bethany v. FERC*, 727 F.2d 1131, 1136 (D.C. Cir. 1984); *see also ISO New England Inc.*, 114 FERC ¶ 61,315 at P 33 and n.35 (2006) (citing *Pub. Serv. Co. of N.M. v. FERC*, 832 F.2d 1201, 1211 (10th Cir. 1987) and *Bethany*, 727 F.2d at 1136).

[10] *Oxy USA, Inc. v. FERC*, 64 F.3d 679, 692 (D.C. Cir. 1995).

[11] *Cf. S. Calif. Edison Co.*, 73 FERC ¶ 61,219 at 61,608 n.73 (1995) ("Having found the Plan to be just and reasonable, there is no need to consider in any detail the alternative plans proposed by the Joint Protesters.") (citing *Bethany*, 727 F.2d at 1136).

[12] NERC requires that each Balancing Authority "have an Operating Plan(s) for the next-day that addresses: . . . [e]xpected generation resource commitment and dispatch"; . . . [i]nterchange scheduling; . . . [d]emand patterns; . . . and [c]apacity and energy reserve requirements, including deliverability capability." NERC Standard TOP-002-4 – Operations Planning, R.4, *available at* https://www.nerc.com/pa/Stand/Reliability%20Standards/TOP-002-4.pdf (accessed on Oct. 24, 2023).

[13] *See* White Testimony at 9–17.

[14] *See id.* at 31–33; *see also* Order No. 897 at P 2, *One-Time Informational Reports on Extreme Weather Vulnerability Assessments: Climate Change, Extreme Weather, and Electric System Liability*, 88

The increased use of weather-dependent resources, combined with shifting energy use patterns and a drive toward electrification, will create an energy landscape in New England that is increasingly weather dependent at a time when more severe weather events are predicted for the future. Because of the inherent challenges of having more weather-dependent resources and greater variability in energy production on the system, the New England power system will require a greater ability to respond to operational uncertainties during the Operating Day by calling on flexible resources.[15]

DASI will provide targeted compensation and clear financial obligations and incentives for the flexible resources on which the region currently relies, and on which it will increasingly rely as the region heads into the future.[16] Specifically, the proposal creates a Day-Ahead Ancillary Services Market, to be run jointly with the current Day-Ahead Energy Market, that will procure ten- and thirty-minute operating reserves from fast-ramping and fast-starting resources sufficient to meet the anticipated Real-Time reserve requirements for the next day. The design of the proposed joint Day-Ahead Market is described in Section V below. Relying on priced offers from energy and ancillary services suppliers, priced energy demand bids, and the projected load and reserve requirements for the Operating Day, the proposed Day-Ahead Market will clear energy and ancillary services jointly in a way that maximizes the efficient use of the region's resources to meet Day-Ahead energy demand and to satisfy both the load forecast and Day-Ahead reserve requirements. In short, the jointly optimized Day-Ahead Market proposed here will "solve" (*i.e.*, generate a schedule of awards) for the most cost-effective solution that will

Fed. Reg. 41,477 (2023) (to be codified at 18 C.F.R. pt. 141) ("[T]he frequency and severity of extreme weather events is increasing. A robust and growing body of scientific evidence attributes this trend to climate change and indicates that this trend will persist.") (footnotes omitted); Order No. 896 at P 2, *Transmission System Planning Performance Requirements for Extreme Weather*¸ 88 Fed. Reg. 41,262 (2023) (to be codified at 18 C.F.R. pt. 40) ("Extreme heat and cold weather events have occurred with greater frequency in recent years, and are projected to occur with even greater frequency in the future.") (footnotes omitted).

[15] White Testimony at 31–35. In its broader proceeding on Modernizing Wholesale Electricity Market Design, the Commission has heard from system operators regarding the need to address changing system needs and of "the value of [market] reforms that direct payments to the resources that actually help to meet system needs." *Modernizing Wholesale Electricity Market Design*, 179 FERC ¶ 61,029 at P 35 (2022) (recognizing comments, including those from ISO New England Inc.).

[16] The ISO's External Market Monitor ("EMM") recommended that the ISO pursue the procurement of ancillary services in the Day-Ahead market. In doing so, the EMM noted, "Under-compensating generators that have flexible characteristics will be increasingly undesirable as the penetration of intermittent renewable generation increases over the coming decade because these resources will be essential to complement intermittent resources and maintain reliability." Potomac Economics, *2021 Assessment of the ISO New England Electricity Markets*, at 28–29 (June 2022), *available at* https://www.iso-ne.com/static-assets/documents/2022/06/iso-ne-2021-som-report-full-report-final.pdf. It also stated, "Procuring and pricing these requirements in the day-ahead market would result in substantial additional net revenues, especially for flexible resources such as fast-ramping peaking units and battery storage units that will be helpful for integrating intermittent renewable generation." *Id.* at 32.

satisfy energy demand and reserve requirements. This type of jointly optimized clearing of energy and ancillary services is not new to Regional Transmission Organizations ("RTOs") and Independent System Operators ("ISOs"), and the procurement of ancillary services in a jointly optimized day-ahead market is not novel.[17]

The two less familiar aspects of DASI, at least in the context of other RTO/ISO day-ahead markets, are (1) the inclusion of a reserve product (in addition to the Day-Ahead reserves) intended to help cover any Day-Ahead energy gap, which the ISO refers to as the Day-Ahead Energy Imbalance Reserve ("DA EIR"), and (2) the settlement of Day-Ahead Ancillary Services using Real-Time energy prices with what the ISO is referring to as a call-option settlement structure. As to the first novel aspect of DASI, DA EIR awards in combination with Day-Ahead energy awards will close the Day-Ahead energy gap in the proposed joint Day-Ahead Market, as explained further below in Section V.C.3.

The second novel aspect, the call-option settlement structure, is motivated by the need to properly value the Day-Ahead reserves for what they are—options on resources' energy in Real-Time. As explained further below in Section V.B and in Dr. White's testimony, the call-option settlement design uses expectations of Real-Time energy market prices to determine a "strike price" in the Day-Ahead Market. Suppliers will make Day-Ahead Ancillary Services Offers knowing this strike price, understanding that by taking on (and, importantly, receiving a clearing price for) a Day-Ahead Ancillary Services award, the resource is expected to be ready to produce energy in Real-Time to meet that award and will receive, at most, the strike price for the Real-Time energy it produces.[18]

Further, the call-option settlement structure includes a "close-out charge" to suppliers with Day-Ahead Ancillary Services awards, which sets the suppliers' liability for non-performance (*i.e.*, a failure to produce energy when needed by the system). As explained further below and in Dr. White's testimony, the close-out charge creates a non-performance charge based on the Real-Time replacement cost of energy. Importantly, this structure creates a "no fault" liability for non-performance and sets the liability amount at what is economically efficient for the system. The close-out charge creates strong incentives for resources with Day-Ahead Ancillary Services awards to perform as dispatched in Real-Time.

Paired with this market design, the ISO also proposes a set of market power mitigation rules that will screen for and mitigate the exercise of market power in the Day-Ahead Ancillary

[17] *See* Ewing Testimony at 42 ("This type of joint optimization across Day-Ahead products is similar to the joint optimization of the Real-Time market clearing engine across energy and Operating Reserve products, and is similar to the joint optimization process that occurs in many other regions' Day-Ahead markets.").

[18] As discussed in Section V.B below, despite potential differences between (1) the Real-Time LMPs paid for Real-Time energy awards and (2) the Real-Time Hub Price used as a basis for a resource's close-out settlement for its Day-Ahead Ancillary Services award, the ultimate price the region pays for the ancillary services supplier's Real-Time energy would be close to the strike price, in most cases.

Services Market. The design of the market power mitigation rules is discussed in Section VI below. To address economic withholding and physical withholding, the ISO proposes conduct-and-impact test structures that are robustly supported by quantitative analyses conducted using simulations of the proposed Day-Ahead Ancillary Services Market and joint Day-Ahead Market. The ISO also proposes revisions to today's consultation process with the Internal Market Monitor ("IMM") and mitigation-related cost-recovery process that will include the Day-Ahead Ancillary Services Market in those processes.

The ISO conducted an assessment of the revenues DASI will generate for suppliers in the region and, consequently, the costs to load for the proposed changes. This assessment is described in Section VII below. The results of the assessment showed that DASI will direct revenues to the types of flexible resources on which the region relies daily, including both dispatchable fuel-fired generators and storage resources. Although the region had few battery storage resources during the assessment's 2019–2021 study period, the assessment showed that pumped storage resources earn substantial revenues from the new Day-Ahead Ancillary Services Market, suggesting the same will be true for the new battery storage resources that are entering the New England system. The overall cost to load estimated by this assessment for the years studied was an average annual increase in wholesale market costs of 1.4 percent, which is reduced to 1.1 percent if one includes the savings resulting from the elimination of the Forward Reserve Market (included in the DASI proposal and discussed in Section V.I) and projected reductions in Net Commitment Period Compensation ("NCPC") costs.

Overall, DASI addresses the under-compensation of flexible resources relied on by the region for developing reliable next-day Operating Plans and does so using a market that will also provide the right incentives for those resources to be prepared to produce energy in Real-Time, with minimal cost impacts to load. Further, the Day-Ahead Market structure that will be implemented as part of DASI, if accepted by the Commission, will provide a platform for future ancillary services innovations, such as longer-duration reserves, that can provide additional flexibility and reliability to the system and support the region's evolving resource mix and efforts toward decarbonization.[19] The ISO thereby requests that the Commission accept the DASI proposal, as it represents a high-value market reform that will support the region's energy future.

IV. NEW ENGLAND'S EXISTING DAY-AHEAD ENERGY MARKET

The ISO has long administered a Day-Ahead Energy Market that enables market participants to buy and sell energy one day ahead of each Operating Day. The Day-Ahead Energy Market establishes financially binding forward positions for the supply and demand of energy provided the next day. The market includes transactions for physical supply from within

[19] *See* White Testimony at 48–49. For clarity, the ISO does not propose as part of DASI any type of longer duration operating reserves. The ISO intends to explore the value of pursuing longer-duration reserve products, especially in light of growing interest in such reserves throughout the industry. Report of ISO New England Inc., at 50, 54–55, *Modernizing Wholesale Electricity Market Design*, FERC Docket No. AD21-10-000 (filed Oct. 18, 2022).

the region, imports and exports, and virtual transactions. Having a Day-Ahead market for energy provides the region with the benefits of reduced volatility in energy costs and of contributing, in part, to creating a reliable Day-Ahead Operating Plan.[20]

A. Deviation Settlement and Replacement Cost of Energy

The energy market employs a multi-settlement process that is common among RTOs and ISOs with day-ahead markets. This settlement process, which can be referred to as producing a "deviation" settlement, is simple. A seller of energy is obligated to provide the megawatt-hours ("MWh") of energy in its Day-Ahead energy award during the hour of the Operating Day associated with the award (the "award-hour").

If the seller provides fewer MWh of energy—that is, underperforms—then, during settlement, it must "close out" its Day-Ahead energy position through a charge for the MWh deviation from its Day-Ahead award (*i.e.*, the MW quantity of its under-performance) at the applicable Real-Time LMP. In this way, the seller becomes financially liable for replacing those MWh of energy at the cost to the system of procuring those MWh in Real-Time from another seller, which is the Real-Time energy price.[21] This cost, the replacement cost of energy, ensures that sellers have a strong incentive to perform in Real-Time consistent with their Day-Ahead energy awards.[22]

The deviation settlement approach is based on the simple and powerful economic principle of replacement cost.[23] Specifically, this principle is that if a seller does not deliver consistent with a financially binding obligation, it must either replace the goods it cannot deliver with those from another seller, or it must pay the buyer's cost to do so.[24] The deviation settlement—which charges Real-Time energy prices for deviations from the Day-Ahead award obligation—serves both of these functions. It identifies, through use of the Real-Time energy price (which by design is the system's incremental cost of acquiring replacement energy), the least-cost supplier than can deliver incremental energy in Real-Time and charges this price to any seller that delivers less than its Day-Ahead obligation.[25]

[20] White Testimony at 4–6.

[21] *Id.* at 6–9.

[22] *Id.* at 5–9. Conversely, for sellers that provide MWh of energy in Real-Time in excess of their Day-Ahead awards, those sellers receive a credit for the MWh deviation at the applicable Real-Time LMP. Buyers are also charged or credited for any deviation between the amount of energy they take delivery of in Real-Time and the amount they purchased Day-Ahead.

[23] *See id.*

[24] *Id.* at 7–8.

[25] *See id.*

This is a "no fault" approach to the failure to deliver that, most importantly, ensures the efficient use of resources on the system. Namely, it provides sellers the incentive to make investments (and, consequently, incur costs) to ensure they can produce energy in Real-Time, but only so far as the costs of those investments do not exceed the expected replacement cost of energy in Real-Time.[26]

B. Current Contribution to a Reliable Day-Ahead Operating Plan

The Day-Ahead Energy Market, in part, contributes to the region's next-day Operating Plan. As the Balancing Authority for New England, the ISO must develop a reliable next-day Operating Plan in accordance with NERC standards. Specifically, NERC standards require that Balancing Authorities develop an Operating Plan that addresses "capacity and energy reserve requirements, including deliverability capability" and that balances "expected generation resource commitment and dispatch . . . interchange scheduling . . . and demand patterns."[27] To address this requirement, the ISO identifies Day-Ahead the resources that will be available to meet the load forecast during each hour of the Operating Day and the resources that will be able to provide ten- and thirty-minute operating reserves during those hours—as set forth in the ISO Tariff and operating procedures in accordance with NPCC standards.[28] The Day-Ahead Energy Market currently contributes to the region's Operating Plan by creating a schedule of commitments to provide energy during the Operating Day through Day-Ahead energy awards.

The Day-Ahead Energy Market is not currently designed to ensure that sufficient capability is available to satisfy either the load forecast or to provide the ten- and thirty-minute operating reserves expected to be needed in Real-Time. The Day-Ahead Energy Market only procures energy to meet bid-in demand, and if the load forecast exceeds the amount of cleared energy from physical suppliers, there remains what the ISO refers to as a Day-Ahead "energy gap."[29] The Day-Ahead Energy Market also does not procure (*i.e.*, produce awards for) the ten- and thirty-minute operating reserves the region is anticipated to need in Real-Time.

Instead, the ISO, in developing the next-day Operating Plan, currently takes non-market actions to identify the energy and reserve capabilities necessary to satisfy the load forecast, if a Day-Ahead energy gap exists, and anticipated operating reserve needs. With regard to identifying necessary operating reserve capabilities for the next day, the ISO's Day-Ahead market clearing engine ("MCE") does have a role to play, even though that role does not extend to issuing Day-Ahead reserve awards. The MCE has two processes, a unit-commitment process

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[26] *See id.* at 8.

[27] Ewing Testimony at 5–7 (citing the relevant NERC standards).

[28] *Id.* at 5–8.

[29] *Id.* at 7–8, 20.

and an economic dispatch and pricing process.[30] The unit-commitment process, but not the economic dispatch and pricing process, incorporates anticipated operating reserve needs for the next day when determining which resources will be scheduled to provide energy (that is, scheduled to be "online") for the next day and which resources will not be (that is, scheduled to be "offline").[31] This process only identifies which resources are anticipated to be available to provide operating reserves during each hour of the next day, and it does not result in commitments to provide reserves, compensation, or even notice to the resources on which the region is relying when formulating the next-day Operating Plan.[32] Consequently, the identification of resources that will provide next-day operating reserves occurs outside of the Day-Ahead Energy Market's market mechanisms.

The load forecast, and therefore any energy gap, is not incorporated into either MCE process. Instead, any part of the load forecast not satisfied by cleared Day-Ahead energy is addressed through an out-of-market reliability process known as the Reserve Adequacy Analysis ("RAA"). The RAA process finds on an hourly basis any gap between the load forecast and the total energy from physical resources and net imports that cleared in the Day-Ahead Energy Market, and it identifies resources that will be able to fill that gap for purposes of the Operating Plan.[33] Through the RAA process, the ISO also may commit, in rare circumstances, additional units to meet the next day's operating reserve requirements.[34] Resources do not receive awards or compensation when they are identified through this process as being available to satisfy the load forecast or operating reserve requirements, nor are they notified by the ISO when they are identified as such.[35]

The lack of direct, targeted compensation for these services is a growing concern for the ISO. Although the unit commitment and RAA processes result in identifying resources day-ahead to satisfy the needs of the Operating Plan, there is no incentive for those resources to begin preparations to be able to provide energy during the hours of the Operating Day for which they were identified as a source of reserves.[36] Consequently, there is no incentive for the resource to begin taking costly actions to ensure they can produce energy during those hours.[37] These actions include, for natural gas-fired resources, making additional fuel arrangements to be able to run for longer or to produce more energy than required by their Day-Ahead energy awards; for

[30] Ewing Testimony at 7. These are also referred to as security-constrained unit commitment ("SCUC") and security-constrained economic dispatch ("SCED"), respectively.

[31] *Id.*

[32] *Id.* at 7–8.

[33] *Id.* at 8.

[34] *Id.*

[35] *Id.* at 7–8; White Testimony at 10–12.

[36] White Testimony at 9–17.

[37] *Id.*

storage resources, additional costs to store energy in order to deliver during the hour on short notice; and for infrequently-operating "peaking" generators, potentially arranging additional staff to ensure reliable start-up on short notice.[38]

As explained in Dr. White's testimony, the ISO markets currently do not provide compensation targeted to these discrete costs related to being identified as reserves, and thus on-call to produce energy, during specific hours of the next day.[39] Real-Time reserve compensation is not sufficient because the ISO's Real-Time reserve market compensation is based only on the opportunity cost of not supplying energy in Real-Time, and Real-Time Operating Reserve prices are rarely non-zero.[40] And Forward Capacity Market payments are not designed to compensate the specific reserve capabilities—namely, the fast-ramping and fast-starting capabilities—that are required to provide the operating reserves needed for the next day.[41]

Finally, the ISO's current Forward Reserve Market ("FRM") provides compensation to resources unrelated to whether those resources are being relied on by the ISO as part of the next-day Operating Plan. The resources relied on in formulating the Operating Plan can change daily, and they include resources scheduled to be online and producing energy during the Operating Day that can provide spinning (*i.e.*, synchronized) reserves to meet the next day's ten-minute spinning reserve requirements.[42] The FRM does not procure any ten-minute spinning reserves on a forward basis. The FRM also has no mechanism for compensating resources identified Day-Ahead as available to satisfy forecasted load in Real-Time.[43]

In sum, the process the region currently uses to identify specific resources to formulate a reliable next-day Operating Plan that meets concrete NERC and NPCC reliability standards does not result in compensation for the reliability attributes directly required by those standards. Further, although these resources may have certain obligations under the Forward Capacity Market or more general obligations under the ISO's governing documents to be available during a given Operating Day, this process does not result in any precisely defined obligation (or notice, for that matter) for those resources to act as reserves (that is, on stand-by to produce energy) in accordance with that next-day Operating Plan. It is also a non-market-based process that, when

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[38] *Id.* at 16–17.

[39] *See id.* at 12–13, 15–17.

[40] *Id.* at 17–20.

[41] *Id.* at 22–25.

[42] *See* White Testimony at 12–13, 21–22. Although the FRM procures forward Ten-Minute Non-Spinning Reserves ("TMNSR") and Thirty-Minute Operating Reserves ("TMOR"), it does so seasonally, far in advance of the Operating Day and only for certain hours of non-holiday weekdays. *See* Ewing Testimony at 74. It does not procure any forward Ten-Minute Spinning Reserves ("TMSR").

[43] *See* White Testimony at 22.

it results in additional commitments, has the potential to suppress Real-Time prices and increase uplift (that is, NCPC) payments.[44]

V. PROPOSED DAY-AHEAD MARKET AND DAY-AHEAD ANCILLARY SERVICES MARKET

To address the lack of compensation, obligations, and notice regarding the region's reliance on reserve capabilities specific to the next-day Operating Plan, the Filing Parties propose a Day-Ahead Ancillary Services Market, to be run and cleared jointly with the Day-Ahead Energy Market, that will solicit priced offers for new ancillary services products defined specifically to satisfy the load forecast and the next-day operating reserve requirements. The joint clearing of the new Day-Ahead Ancillary Services Market and the existing Day-Ahead Energy Market constitutes the newly defined Day-Ahead Market.

The Day-Ahead Ancillary Services Market includes four new Day-Ahead Ancillary Services products: Day-Ahead Ten-Minute Spinning Reserves ("DA TMSR"); Day-Ahead Ten-Minute Non-Spinning Reserves ("DA TMNSR"); Day-Ahead Thirty-Minute Operating Reserves ("DA TMOR"); and DA EIR. The first three products are intended to satisfy the next-day ten- and thirty-minute operating reserve requirements, and the ISO refers to them collectively as the Day-Ahead Flexible Response Services. The fourth product, the DA EIR, is a reserve product that will contribute to satisfying the load forecast when cleared Day-Ahead energy awards to physical resources are insufficient to do so. The four products will each have a clearing price, and the market will result in awards to resources that clear for each product.

The ISO is designing each of these new Day-Ahead reserve products in a way that represents their true value to the overall system—which is an option, purchased Day-Ahead, for the system to call upon the resources to produce energy when necessary in Real-Time, *i.e.*, a call option. The ISO will not, in a literal sense, "call" on a resource with a Day-Ahead Ancillary Services award during the Operating Day as though it were a person exercising a securities option. Rather, the call-option settlement structure lets market conditions do the talking (that is, the Real-Time market clearing engine dispatches the resource if, in Real-Time, it becomes in-merit).[45] This call-option settlement structure, described further below, allows the region to better reflect the value of contributing to the next-day Operating Plan, which is the region's reliance on the resource to either continue to stand by as reserves in Real-Time *or* produce energy when market conditions send the signal. The call-option settlement structure also creates an economically-efficient, "no fault" financial obligation for when the resource fails to perform in Real-Time.

The following describes the ISO's rationale for choosing a market-based solution, the call-option settlement structure, and the overall design of the proposed Day-Ahead Ancillary Services Market and joint Day-Ahead Market. The rationale for a market-based solution is

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[44] Ewing Testimony at 8.

[45] *See* White Testimony at 52–54.

discussed in Section V.A. The call-option settlement structure is discussed in Section V.B. The proposed Day-Ahead Market's reserve requirements (referred to as "demand quantities") and products satisfying them are discussed in Section V.C. Resources' eligibility to provide the new products is discussed in Section V.D. How resources will formulate and make offers for Day-Ahead Ancillary Services are discussed in Sections V.E and V.F. The awards and clearing prices produced by the joint Day-Ahead Market are discussed in Section V.G. Settlements and cost allocation are discussed in Section V.H, and the retirement of the FRM is discussed in Section V.I.

A. Rationale for Market-Based Procurement of Day-Ahead Ancillary Services

As a foundational matter, a market-based procurement of these products as proposed has the benefit of compensating resources in a targeted way for the service they provide to the region—contributing to a reliable next-day Operating Plan—through the efficient marginal-cost-based pricing that results from a competitive market. Importantly, competitive markets are a means to find the most cost-effective providers of a service.[46] A competitive market with a transparent, uniform-clearing price disciplines sellers to bid at-cost and provides signals to the market of when the services procured through the market are in greatest demand, encouraging investment from existing suppliers as well as new entry.[47] As Dr. White explains, transparent pricing from a competitive market can foster innovation, encouraging entry from sellers that anticipate providing the service at lower costs, or with superior performance, or both.[48] Lastly, a competitive market results in a clearing price that reflects the marginal cost to the market overall of procuring the last unit of the needed service.[49] Thus, it determines the cost necessary to replace the services of a seller that fails to deliver, *i.e.*, the replacement cost.[50]

In sum, a competitive Day-Ahead Ancillary Services Market, through the transparent price signals sent by the clearing prices for the four products above, will not only compensate the resources the region regularly relies on for its next-day Operating Plans, but it will do so in a way that efficiently values these products and seeks the most cost-effective means of procuring them. A market-based solution also leaves open the potential for new entry and innovation that would not otherwise exist through a continued administrative process, and eliminates the potential for price distortion and increased uplift payments noted above.[51]

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[46] *Id.* at 28.

[47] *Id.* at 29–31.

[48] *Id.*

[49] *See id.* at 36 (noting that competitive market will render clearing price reflecting "system's marginal cost to procure an incremental amount of each service").

[50] *Cf. id.* at 7 (competitive Real-Time energy price reflects system's marginal cost and, thus, replacement cost).

[51] *See* Ewing Testimony at 8.

B. Call-Option Settlement

At a high-level, the call-option settlement structure is a two-settlement structure by which a resource with a Day-Ahead Ancillary Services award receives (1) a credit for its Day-Ahead Ancillary Services award and (2) a "close-out charge." The credit to a supplier for a Day-Ahead Ancillary Services award is simply the quantity of the award, multiplied by the Day-Ahead Ancillary Services product's clearing price. The close-out charge to the supplier is the quantity of the award multiplied by the greater of (i) zero and (ii) the difference between the Real-Time Hub Price and an ISO-determined "strike price." The derivation and effects of this two-settlement structure are explained below.

1. The Call-Option Settlement Structure

a. *Conceptual Basis for the Call-Option Settlement Structure*

As noted above, the call-option settlement structure properly values the Day-Ahead Ancillary Services for what they are—options on energy in Real-Time. Broadly, procuring ancillary services Day-Ahead ensures there will be sufficient resources that the region can call on short notice, if needed, to balance energy supply and demand the next day.[52] The fundamental value of these Day-Ahead reserves is the reserve resources' ability to promptly deliver energy in Real-Time when market conditions require it. Consequently, "delivering" these services takes the form of either (1) acting as reserves in Real-Time for the period of time associated with the Day-Ahead Ancillary Services award (the "award-hour"), if the resource's energy offer in Real-Time is out-of-merit (*i.e.*, too high to clear and exceeds Real-Time energy prices) or (2) producing energy in Real-Time during the award-hour, when the resource's energy offer is in-merit.

The consequences of a resource failing to perform as reserves in Real-Time and failing to perform as energy in Real-Time have different impacts on the market. When Real-Time energy prices are low enough during the award-hour such that the resource would not be in-merit for energy in Real-Time, the impact of non-performance is minimal.[53] In this situation, the resource's energy is not required in Real-Time, and there is no missing energy to replace.[54] Moreover, as Dr. White explains, replacing any Real-Time reserves is of no cost to the system because sufficient reserves are generally available in conditions where energy prices are lower, and the region can meet its Real-Time reserve requirements without additional action.[55]

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[52] *Id.* at 52.

[53] *See id.* at 54–56.

[54] *See id.*

[55] *Id.*; *see also* Ewing Testimony at 17 (explaining current sufficient reserve capabilities on system).

When Real-Time energy prices are high enough such that the resource would be in-merit for energy in Real-Time, however, the impact of non-performance is greater. In that case, the resource fails to provide energy, and the ISO must then turn, in possibly tight and unexpected operating conditions, to higher-cost resources to replace the energy not delivered by the resource.[56] Such non-performance increases the system's total costs and the Real-Time price of energy.[57] Replacement costs in this circumstance, similar to replacement costs for failure to provide energy in Real-Time consistent with a Day-Ahead energy award, should be based on the system's Real-Time energy costs.[58]

As a result, consistent with replacement-cost logic, the ISO is proposing a Day-Ahead Ancillary Services settlement structure that reflects the replacement costs of these two types of non-performance through the call-option settlement structure.[59] The call-option settlement structure consists of two settlements. The first settlement is a credit to the supplier with a Day-Ahead Ancillary Services award at the applicable Day-Ahead Ancillary Services clearing prices. The second settlement is a close-out charge to the supplier that occurs when Real-Time energy prices exceed an ISO-determined strike price.

The strike price for this close-out charge will be set Day-Ahead, prior to Day-Ahead Market offers, to reflect the expectations of Real-Time energy prices, and it serves to delineate the two types of non-performance described above. Consider a resource that has a one MWh Day-Ahead Ancillary Services award from the Day-Ahead Market. This means that, under the Real-Time market conditions expected at the time the Day-Ahead Market is run, the resource's one MWh of potential energy output was not anticipated to be dispatched in Real-Time, only that the one MWh of potential energy output *may* be needed if system conditions tighten (*e.g.*, a contingency occurs). Taking expected Real-Time energy prices as a reflection of expected Real-Time market conditions, a strike price based on expected Real-Time energy prices would represent the Real-Time energy price at which the resource's one MWh of energy is not expected to be needed *unless* system conditions tighten. A strike price based on expected Real-Time energy prices therefore also represents the Real-Time energy price above which the resource's one MWh of energy is expected to be needed. Consequently, a strike price based on the expected Real-Time energy price can delineate the price at which or below which the anticipated replacement cost of non-performance will be the replacement cost of Real-Time reserves, and above which the anticipated replacement cost of non-performance will be the replacement cost of Real-Time energy.[60]

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[56] White Testimony at 55–56.

[57] *Id.* at 56.

[58] *Id.* at 56–57.

[59] *See id.* at 57–58.

[60] *See id.* at 57, 60 (explaining strike price as way "to delineate the bifurcated settlement outcomes" and replacement costs related to two types of non-performance).

The close-out charge is calculated as the difference between the Real-Time Hub Price, which reflects the region's Real-Time energy prices as a whole, and the strike price, whenever the Real-Time Hub Price exceeds the strike price.[61] Otherwise, the close-out charge is zero.[62] The result is that a Day-Ahead Ancillary Services supplier does not receive a close-out charge whenever the Real-Time Hub Price is equal to or less than the strike price—that is, when Real-Time market conditions either reflect or are less demanding than those expected Day-Ahead—and the only replacement cost is effectively zero.[63] The supplier receives a close-out charge whenever the Real-Time Hub Price exceeds the strike price, however. In that circumstance, where Real-Time market conditions are tighter than expected Day-Ahead, the close-out charge reflects the replacement cost of energy the system incurs if the resource fails to produce energy in Real-Time during those conditions.[64]

b. *Effects of the Call-Option Settlement Structure*

Dr. White walks through a number of examples showing that the call-option settlement has two major effects. The first effect is that the call-option settlement effectively caps a Day-Ahead Ancillary Services supplier's Real-Time energy revenues at or near the strike price.[65] As mentioned above, there are two types of performance: the resource either acts as reserves in Real-Time, if it is out-of-merit for energy; or, the resource produces energy in Real-Time if it is in-merit. If the resource produces energy in Real-Time, it will be credited the Real-Time LMP, in addition to the credit it receives for its Day-Ahead Ancillary Services award. However, the resource's overall credits and charges for this Real-Time energy are the Real-Time LMP minus the close-out charge.

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[61] As explained further below in Section V.C.1, the region is procuring the new Day-Ahead reserves products on a region-wide, rather than zonal, basis. Consequently, the ISO is using the Real-Time Hub Price as the best representation of the replacement cost to the entire system because it is an average of certain nodal Real-Time LMPs. *See also id.* at 79–81 (explaining choice of Real-Time Hub Price).

[62] Dr. White provides the formula for the close-out charge as max{0, RT Hub Price – K}, with K representing the strike price. *Id.* at 61.

[63] *See id.* at 62–64.

[64] *See id.* at 56–59, 62, 64–68 (explaining concepts and illustrating close-out when Real-Time Hub Price exceeds strike price). Using the Real-Time replacement cost of energy to settle reserves is not without precedent. Although imposed as a non-performance penalty, Midcontinent Independent System Operator ("MISO") charges a "Contingency Reserve Deployment Failure Charge" that is based on "the average of the Real-Time Ex Post LMP" to Contingency Reserves that have failed to deploy. MISO Tariff, Module C, Section 40.3.4(e)(i); *see also* MISO Tariff, Module C, Section 40.3.4(f)(i) (imposing "Short-Term Reserve Deployment Failure Charge" based on Real-Time Ex Post LMP for deployment failure).

[65] White Testimony at 64–65 (showing net settlement at strike price when Real-Time price is higher than strike price).

The close-out charge effectively caps the resource's Real-Time energy credits at or near the strike price because the strike price is formulated using the Real-Time Hub Price. The close-out charge to a supplier is either zero or the difference between the Real-Time Hub Price and the strike price (when positive). If the resource is in-merit to produce energy in Real-Time, the supplier will earn energy revenues at the applicable Real-Time LMP. If the applicable Real-Time LMP for the resource's energy award is the Real-Time Hub Price, then the overall price at which the resource sells energy in Real-Time is never greater than the strike price.[66] This effect is consistent with the "option" aspect of the settlement design in that, by paying the supplier for taking on a Day-Ahead Ancillary Services award, the region is entitled to purchase energy from the supplier at a price no greater than the strike price.[67]

The second effect is that the call-option settlement, with its potential for substantial close-out charges when Real-Time energy prices exceed the strike price, creates incentives for suppliers with Day-Ahead Ancillary Services awards to be prepared to produce energy in Real-Time if system conditions tighten and the supplier's resource becomes in-merit to provide energy.[68] In order to avoid a loss due to the close-out charge, the resource must be able to respond to higher-than-expected Real-Time energy prices by producing energy in Real-Time and earning Real-Time energy market revenues that offset the close-out charge. The close-out charge creates this incentive by forcing the resource to internalize the replacement cost of energy

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[66] *See id.* By way of further explanation, first consider that the close-out charge is zero whenever the Real-Time Hub Price is less than or equal to the strike price. In that circumstance, a supplier with a Day-Ahead Ancillary Services award that produces energy in Real-Time receives a Real-Time energy credit at the Real-Time Hub Price and is not charged a close-out charge. The net energy revenue for its Real-Time energy sale (setting aside the credit for the Day-Ahead Ancillary Services award itself) is simply at the Real-Time Hub Price, which is less than or equal to the strike price. Consider second that the close-out charge is the Real-Time Hub Price minus the strike price whenever the Real-Time Hub Price exceeds the strike price. In that circumstance, the same supplier receives a Real-Time energy credit at the Real-Time Hub Price but then is charged a close-out charge that is the Real-Time Hub Price minus the strike price. Mathematically, the net Real-Time energy revenue is the Real-Time Hub Price – (Real-Time Hub Price – Strike Price). Simplifying the expression, the net Real-Time energy revenue is the strike price. Consequently, the net Real-Time energy revenue never exceeds the strike price, at least when the Real-Time LMP applicable to a supplier's energy award is the Real-Time Hub Price (see note 67 *infra*, however).

[67] *See id.* at 67 (explaining, through example, that system acquired right to supplier's energy at an "up-front" price of Day-Ahead Ancillary Services clearing price and "incremental price of (at most)" strike price in Real-Time). Due to potential differences between the Real-Time LMPs paid for Real-Time energy awards and the Real-Time Hub Price used as a basis for a resource's close-out charge, the ultimate price a supplier may receive for producing energy in Real-Time under this settlement structure could deviate from the strike price by some amount. Nevertheless, the ultimate Real-Time energy price the region pays for the supplier's Real-Time energy would be close to the strike price, in most cases. *See id.* at 81 (explaining that, due to lack of transmission system congestion, differences between nodal and Real-Time Hub Prices are likely inconsequential).

[68] *Id.* at 69–72.

if the resource fails to produce energy when Real-Time energy prices "call" on the resource (*i.e.*, Real-Time prices are high enough such that the Real-Time market clearing engine would clear the resource's energy offer).[69]

As Dr. White explains, the close-out charge, rather than the Real-Time energy price, is the replacement cost of energy for non-performance. Through the Day-Ahead Ancillary Services award, the system acquires a right to the resource's energy in Real-Time for the combination of (i) an upfront price, set by the applicable Day-Ahead Ancillary Services clearing price and (ii) a maximum energy price, generally, that is at or near the strike price.[70] In Real-Time, load would have had to pay the strike price for energy from the ancillary services supplier even if the resource had performed.[71] Thus, when the resource fails to perform, the incremental replacement cost is just the additional amount load has to pay above the strike price for energy in Real-Time, which is the Real-Time energy price minus the strike price.[72] The close-out charge, therefore—which is the Real-Time Hub Price minus the strike price—reflects the replacement cost of energy.

2. <u>The Call-Option Settlement Structure's Incentives in Context</u>

The ISO reviewed and considered other settlement designs, including those used by other RTOs and ISOs that settle their day-ahead ancillary services against Real-Time reserve prices. As Dr. White explains, settling the ISO's proposed Day-Ahead Ancillary Services awards against the region's Real-Time Operating Reserve prices, which are almost always zero and calculated based solely on the opportunity cost of marginal resources, would have no real financial impact on suppliers that fail to provide reserves or produce energy in Real-Time consistent with their awards.[73] Such a design would not create the beneficial performance incentives that the ISO intends to create using the call-option settlement design.

Similarly, the ISO considered but did not adopt non-performance penalty amounts, which are used in other regions. The call-option settlement design, which imposes a "no fault" financial obligation, obviates the need for any administratively-determined, non-performance penalty amounts.[74] As noted above, the close-out charge represents the replacement cost of energy for the system, which is the marginal cost to the system of procuring additional MWh of Day-Ahead Ancillary Services. If a supplier with a Day-Ahead Ancillary Services award would incur costs greater than the close-out charge in order to be ready to produce energy during the award-hour, then it is more efficient for the system overall to procure Day-Ahead Ancillary

[69] *Id.* at 58–59, 67, 69–72.

[70] *Id.* at 67.

[71] *Id.* at 67–68.

[72] *Id.*

[73] *See id.* at 92–95.

[74] *Id.* at 97–98.

Services from an alternative resource. In this way, the close-out charge already charges back to the supplier the cost to the system for non-performance if the resource fails to produce energy in Real-Time when needed by the system, which is consistent with the sound economic principle of remedying non-performance using the replacement cost of energy.[75] As Dr. White explains, this is a more efficient method of addressing non-performance than setting an administratively-determined penalty amount, which could have negative impacts on Day-Ahead Ancillary Services prices and market participation.[76]

Using the close-out charge is also more efficient than imposing a specific performance obligation, like a firm-fuel obligation, for similar reasons. As Dr. White illustrates, it would be inefficient to require a resource to obtain fuel for every award, as there may be circumstances where the cost of fuel to the resource in question might far exceed the cost of procuring energy from the next available supplier.[77] Further, a firm-fuel obligation or any other specific performance obligation is difficult to craft in a way that captures the replacement cost of energy and could result in unintended negative impacts to both the Day-Ahead Market and Real-Time energy market.[78] The close-out charge has the benefit of not only capturing the replacement costs of non-performance but also avoiding the potential adverse consequences of administratively-determined, non-performance penalties and specific-performance obligations.

3. Setting a Strike Price

The call-option settlement structure relies on an ISO-determined strike price that is published for Market Participants before Day-Ahead Ancillary Services Offers are due. To accomplish the goals of the call-option settlement structure, the strike price should reflect expected Real-Time market conditions during the hour of the Operating Day associated with the

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[75] *See id.* at 98. Also recall that the close-out charge is "zero" when Real-Time Hub Prices do not exceed the strike price and that the replacement cost of energy is charged back to the supplier only when system conditions (signaled by the Real-Time Hub Price) require.

[76] *See id.* at 98–100. Moreover, a design that relies exclusively on administratively determined penalties to enforce the obligation of the award requires some determination of what the "right" penalty is. As Dr. White explains, a charge related to non-performance should be based on replacement costs, which the close-out charge captures using Real-Time energy prices. Adopting a design that instead relies on administratively determined penalties also would have to attempt to capture the same replacement costs, but the result could be less responsive to Real-Time market conditions than the close-out charge is and has the potential to be, in Dr. White's words, "mis-aligned with the system's actual replacement costs." *Id.* at 104 (describing difficulty of creating administrative penalty mechanism in context of firm-fuel obligations).

[77] *See id.* at 102–03.

[78] *Id.* at 103–07 (explaining various, unintended negative impacts, including negative impacts to consumers).

Day-Ahead Ancillary Services Offers. As mentioned above, the strike price will be set to a value reflective of expected Real-Time energy prices.

Setting the strike price within the range of expected Real-Time energy prices is complicated by the close-out charge's role in creating incentives to perform for Day-Ahead Ancillary Services suppliers. The strike price should seek to maximize the incentives for a resource to be ready to produce energy in Real-Time when the region needs energy above what was anticipated by the Day-Ahead Market. As explained by Dr. White, for the purpose of maximizing incentives, the strike price should reflect Day-Ahead Ancillary Services suppliers' marginal costs of producing energy.[79] Further, for reasons related to the variability of suppliers' marginal costs and the need for a single strike price, the basis for an incentive-maximizing strike price should be the system's overall expected marginal cost of energy in Real-Time.[80] The expected value of the Real-Time Hub Price, therefore, was selected as the base strike price.[81]

Maximizing incentives, however, can be balanced against consumer cost considerations.[82] The lower the strike price, the higher the potential close-out charges to sellers (due to the greater potential for the Real-Time Hub Price to exceed that lower strike price). Sellers will build higher potential close-out charges into their Day-Ahead Ancillary Services Offers, thereby raising the prices of these products.[83] A way of reducing consumer costs is to raise the strike price by some measure above the expected Real-Time LMP, but to do so in a way that does not blunt the incentives created by setting the strike price near Real-Time LMP in the first place.[84]

In balancing these two considerations—one, maximizing incentives to perform, and two, reducing consumers costs—the ISO proposes to set the hourly strike price for the Day-Ahead Ancillary Services Market as the expected Real-Time Hub Price plus $10/MWh (subject to the condition explained above that the strike price shall not be less than zero). Because the ISO is procuring the Day-Ahead Ancillary Services products on a region-wide basis (as explained further below) and the Hub is an uncongested location, the ISO is using the expected Real-Time Hub Price, which is an average of certain nodal LMPs, as the base strike price.[85] The $10/MWh, which the ISO is referring to as the "base strike adder," is an adjustment designed specifically to reduce close-out costs—and, ultimately, consumer costs—in a way that does not materially

[79] *See id.* at 82–83.

[80] *Id.* at 82–86.

[81] *Id.* at 86–87.

[82] *Id.* at 81–82.

[83] The role of expected close-out costs in formulating competitive offers is explored further below in Section V.F.

[84] *See id.* at 82, 89.

[85] *See id.* at 86.

impact the incentives created by the close-out charge during times when performance matters most.[86]

In establishing the base strike adder, the ISO relied on a quantitative analysis that showed the $10/MWh adder amount would have limited impact on the overall incentives created by the call-option settlement design. The ISO employed its Gaussian Mixture Model ("GMM"), which is explained further below in Section V.B.4, to conduct market simulations that compared the incentives sellers have (based on changes in expected close-outs) with and without various base strike adders.[87] The ISO evaluated static adders in $5/MWh increments ranging from $5/MWh to $40/MWh, and it also evaluated potential dynamic adders.[88]

Ultimately, the ISO found that the $10/MWh static adder retained almost all of the incentives when system conditions were the tightest and performance in Real-Time was of the greatest importance.[89] When expected Real-Time Hub Prices were in the highest quintile (the average LMP of which was $63/MWh), the simulations showed that a strike price that includes a $10/MWh adder retained 91 percent of incentives compared to using only the base strike price.[90] A strike price with a $10/MWh adder retained 95 percent of incentives when expected Real-Time prices were in the top five percent of prices (with an average expected Real-Time LMP of $88/MWh) and 94 percent of incentives when expected Real-Time prices were in the top one percent of prices (with an average expected Real-Time LMP of $106/MWh).[91] Comparatively, a strike price with a $10/MWh adder retained 58 percent of incentives when expected Real-Time prices were in the lowest quintile (with an average expected Real-Time LMP of $17/MWh).[92]

As explained by Dr. Alivand, the results reflect that, when expected Real-Time prices are highest (signaling high-stress conditions on the system), the supply curve is steepest, and the next resource available to provide energy when an in-merit resource fails to do so has

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[86] Throughout the stakeholder process, the ISO and stakeholders referred to this as a "strike price adder." Technically, the $10/MWh is part of the strike price and not an "adder" to the strike price. Consequently, the term "base strike adder" is more descriptive of the $10/MWh upward adjustment's relationship to the strike price and its other elements.

[87] Alivand Testimony at 18–26. For this analysis, the ISO measured incentives as the simulated change in expected close-out costs for resources with Day-Ahead Ancillary Services awards when they produce energy whenever in-merit (*i.e.*, perform) compared to when they are unable to produce energy (*i.e.*, do not perform). *Id.* at 18–21.

[88] *Id.* at 20, 25–26.

[89] *Id.* at 22–25.

[90] *Id.* at 22–23.

[91] *Id.*

[92] *Id.*

substantially higher marginal costs.[93] Consequently, the $10/MWh adder is less likely to meaningfully reduce the spread between (1) the Real-Time Hub Price that results from relying on this more expensive resource to supply energy and (2) the strike price.[94] The resources with Day-Ahead Ancillary Services awards during those conditions therefore will continue to face high expected close-out charges, despite the $10/MWh adder, and still have an incentive to produce in Real-Time to avoid a loss on their ancillary services awards.[95]

Compared to other static adders, the $10/MWh adder also struck the right balance of maintaining incentives while helping to reduce consumer costs. Compared to a dynamic adder (*i.e.*, one that rises or falls with changes in response to market conditions) that may have better retained incentives during low-stress conditions, the $10/MWh had the benefit of improving consumer savings and keeping the strike price calculation simple and easy to administer.[96] Further, the ISO determined that the adder's impact on low-stress, low-price environments would not significantly impact the Day-Ahead Ancillary Services Market's contributions to reliability.[97]

4. Model to Derive Expected Real-Time LMPs

For the purpose of setting the strike price, the ISO has developed a statistical model that will allow it to predict with relative accuracy the expected Real-Time Hub Price. The ISO's statistical model is a GMM, which is a type of statistical model appropriate for data sets that do not fit into simple normal distributions and demonstrate more asymmetric distributions, like wholesale market electricity prices.[98] In developing the GMM, the ISO trained the model on seven years of Day-Ahead and Real-Time market data, from the years 2012 through 2018.[99] It then tested the model against the market data from 2019 through 2021 to see if the model predicted Real-Time Hub Prices with enough accuracy such that it could reliably be used to determine strike prices. The ISO reviewed the accuracy of the model and found, in market simulations, that the GMM's predictions of the Real-Time Hub Price were highly correlated (with a correlation coefficient of 0.75) with actual Real-Time Hub Prices.[100] This GMM also outperformed the leading commercial vendor's alternative model for predicting Real-Time LMPs, both in terms of a greater correlation coefficient and slightly smaller error values.[101] The

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[93] *Id.* at 23–25.

[94] *See id.*

[95] *Id.* at 24.

[96] *Id.* at 25–26.

[97] *Id.* at 23–24.

[98] *Id.* at 6–10 (describing design of GMM).

[99] *Id.* at 11.

[100] *Id.* at 11–17 (describing test of GMM).

[101] *Id.* at 12–16.

GMM performed well in estimating next-day confidence intervals for Real-Time Hub Prices, predicting coverage probabilities reliably.[102] Finally, the GMM reliably predicted close-out charges, on average underestimating close-out values by only $0.71/MWh.[103]

The ISO has publicly shared the detailed specifications for the GMM and a description of the GMM's input data, which is either publicly available or available through subscription. These details were published as part of a memo to the NEPOOL Markets Committee. This provides transparency regarding the ISO's derivation of the expected Real-Time Hub Prices that will be relied on for setting the strike price and of expected close-out costs, which, as described in Section VI.C.1 below, are an important component of the ISO's market power mitigation rules. The ISO intends to review the GMM periodically to determine whether any updates to the model are needed to ensure its continued accuracy, and it will publish any such updates on its website.

C. Demand Quantities and Day-Ahead Products to Satisfy Them

The demand side of the Day-Ahead Ancillary Services Market is constructed by the ISO using demand quantities that are equivalent to (1) the ten- and thirty-minute operating reserve requirements necessary for the next-day Operating Plan and (2) the load forecast. There are four demand quantities representing Day-Ahead operating reserves, referred to collectively as the Day-Ahead Flexible Response Services Demand Quantities. They are the Day-Ahead Ten-Minute Spinning Reserve Demand Quantity, the Day-Ahead Total Ten-Minute Reserve Demand Quantity, the Day-Ahead Minimum Total Reserve Demand Quantity, and the Day-Ahead Total Reserve Demand Quantity. These Day-Ahead Flexible Response Services Demand Quantities are analogous to the ISO's current Real-Time reserve requirements, meaning that they are defined with reference to the ten- and thirty-minute reserve requirements projected to be needed for each hour of the Operating Day. Specifically, the four Day-Ahead Flexible Response Services Demand Quantities will be set to the Ten-Minute Spinning Reserve Requirement, Ten-Minute Reserve Requirement, Minimum Total Reserve Requirement, and Total Reserve Requirement that the ISO projects will be needed in Real-Time. The demand quantity representing the load forecast is the Forecast Energy Requirement ("FER") Demand Quantity.

1. <u>Regional v. Zonal Demand Quantities</u>

All five demand quantities are set on a region-wide basis. Although the ISO has maintained four reserve zones in its jointly optimized Real-Time energy and reserve market, application of those same zonal demand quantities and zonal procurement of the products in the Day-Ahead Market are not necessary.[104] Because of substantial investment and upgrades to New England's transmission system, the internal interfaces defining these reserve zones no longer

[102] *Id.* at 14–16.

[103] *Id.* at 16.

[104] White Testimony at 44–45.

constrain the availability of reserves to the rest of the system.[105] Moreover, with regard to the FER Demand Quantity, region-wide definition is consistent with the region-wide nature of the load forecast. Thus, region-wide requirements and products are sufficient to accomplish the goals of securing a reliable next-day Operating Plan.[106]

2. Day-Ahead Flexible Response Services Demand Quantities and Products

The Day-Ahead Flexible Response Services products—DA TMSR, DA TMNSR, and DA TMOR—are defined similarly to the ISO's three Real-Time operating reserve products—TMSR, TMNSR, and TMOR, respectively. These products will satisfy the Day-Ahead Flexible Response Services Demand Quantities in the same way that the three Real-Time Operating Reserve products satisfy the four Real-Time reserve requirements.[107] Like TMSR, DA TMSR is provided generally by an online resource that has ten-minute ramping capabilities. Like TMNSR, DA TMNSR is provided generally by an offline resource that has ten-minute ramping capabilities.[108] And like TMOR, DA TMOR is provided by an online or offline resource that has thirty-minute ramping capabilities.[109]

Further, the products will be "cascaded" to satisfy the demand quantities, reflecting the substitutability of these products as to each demand quantity.[110] For example, DA TMSR, DA TMNSR, and DA TMOR can all satisfy the two thirty-minute reserve requirements, Day-Ahead Minimum Total Reserve Demand Quantity and the Day-Ahead Total Reserve Demand Quantity.[111] DA TMSR and DA TMNSR can both satisfy the overall ten-minute reserve requirement, Day-Ahead Total Ten-Minute Reserve Demand Quantity.[112] As a consequence, to take one example, procuring a quantity of DA TMSR from a resource will count toward satisfying all four reserve requirements. The only reserve requirement that can be satisfied by a single product is the Day-Ahead Ten-Minute Spinning Reserve Demand Quantity, which requires ten-minute ramping capability from an online resource and thus can only be satisfied by

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[105] *Id.* at 44.

[106] The ISO intends to re-evaluate the system's reserve zones as part of an upcoming project, and anticipates that any new reserve zone definitions would be implemented in both the Real-Time and Day-Ahead energy and ancillary services markets. *Id.* at 45.

[107] Ewing Testimony at 10–14.

[108] *See id.* at 14. As explained further below, certain resources composed of multiple generating units may be able to both be "online" and receive a DA TMNSR award.

[109] *Id.* (describing the three products).

[110] *Id.* at 14–17.

[111] *Id.* at 14–15. Mr. Ewing explains further the difference between these two thirty-minute reserve requirements, which is the same difference that exists between their Real-Time analogues, the Minimum Total Reserve Requirement and the Total Reserve Requirement. *See id.* at 11 n.5, 13 n.7.

[112] *Id.* at 14.

DA TMSR.[113] Ultimately, the three Day-Ahead Flexible Response Services products will satisfy these reserve requirements in the same way the Real-Time Operating Reserve products satisfy Real-Time reserve requirements, except that priced offers for the Day-Ahead Flexible Response Services products will clear against the Day-Ahead demand quantities.[114]

3. The FER Demand Quantity, DA EIR, and Physical Day-Ahead Energy

The FER Demand Quantity is equal to the load forecast. Its incorporation into the proposed Day-Ahead Market ensures that the load forecast is treated as demand separately and distinctly from energy demand that is bid in by load in the Day-Ahead Energy Market. In other words, it resolves any Day-Ahead "energy gap" that would have existed under current market rules.

Two products procured in the proposed Day-Ahead Market can satisfy the FER Demand Quantity. The first product is the new DA EIR product, which is a reserve product that has no Real-Time analogue. Because DA EIR serves the purpose of helping the proposed Day-Ahead Market close the Day-Ahead energy gap, it can only be provided by physical supply resources, that is, those resources that may be dispatched in Real-Time to satisfy load.[115] Further, DA EIR awards are limited by a resource's sixty-minute ramping capability, which is the same ramping limitation on hour-to-hour energy award changes (once a resource is online) in the Day-Ahead Energy Market.[116] The ISO designed this new reserve product as a way to help close the energy gap because of the uncertainty as to whether Real-Time load may be higher, or lower, than the load forecast.

The second product is Day-Ahead energy supplied by Generator Assets, Demand Response Resources ("DRRs"), and net imports (that is, aggregated Day-Ahead cleared imports net of Day-Ahead cleared exports)—which are all physical supply resources. Cleared energy awards from these physical supply resources all contribute to satisfying the FER Demand Quantity in each hour.[117] As explained further below, Day-Ahead energy cleared by virtual transactions, because they are not backed by physical supply, cannot contribute to satisfying the FER Demand Quantity.

Cleared energy awards from physical supply resources, in a sense, "close" the Day-Ahead energy gap. To illustrate this, consider a Day-Ahead Energy Market outcome where, after energy offers are cleared against demand bids, the quantity of cleared Day-Ahead energy

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[113] *Id.*

[114] Mr. Ewing further elaborates on and provides examples of how "cascading" functions with regard to reserve products. *Id.* at 14–17.

[115] *Id.* at 18.

[116] *See id.* at 19, 26.

[117] *Id.* at 18–19.

from physical resources is less than the load forecast, resulting in a gap. Under the proposed changes, the Day-Ahead market clearing engine (*i.e.,* MCE) will treat the FER Demand Quantity (*i.e.*, load forecast) as a demand constraint and seek to procure some combination of additional energy supply offered into the market from physical resources and DA EIR to satisfy that demand constraint.[118] In determining this combination, the MCE will determine the combination of these two products that is the most cost-effective way of satisfying the load forecast, and it may determine that clearing some amount of additional energy supply is the most cost-effective way of doing so.[119]

In his testimony, Mr. Ewing provides a simple example of how the MCE may clear additional physical energy supply in lieu of DA EIR to satisfy the FER Demand Quantity.[120] This simplified example illustrates how the MCE's optimization logic will consider the relative costs of procuring DA EIR and Day-Ahead physical energy to satisfy the FER Demand Quantity.

D. Eligibility to Provide Day-Ahead Ancillary Services

Eligibility for suppliers to offer and provide the new Day-Ahead Ancillary Services products is consistent with the function of each of the new products. To be eligible to provide any of the four new products, the supplier must have a resource located within the New England Control Area, must not be constrained by transmission, and must have an open offer to provide energy (or, in the case of DARDs, consume energy) for the hour associated with the Day-Ahead Ancillary Services Offer.[121] All eligibility requirements currently applicable for provision of Real-Time Operating Reserves are applicable to Day-Ahead Flexible Response Services products. Regarding resource types, only resources that are Generator Assets, DRRs, or DARDs are eligible to provide the Day-Ahead Flexible Response Services and only resources that are Generator Assets or DRRs are eligible to provide DA EIR. Eligibility to offer and provide each product, however, is particular to the product. Moreover, virtual supply ("Increment Offers") and imports are not eligible to provide any of the Day-Ahead Ancillary Services products.

1. <u>DA TMSR</u>

Generator Assets, DRRs, and DARDs are eligible to provide DA TMSR provided they meet all of the requirements necessary to provide Real-Time TMSR. This includes being online (*i.e.*, spinning or synchronized), which in the context of the Day-Ahead Market means that the

[118] *Id.* at 20, 50.

[119] *Id.* at 49–52.

[120] *Id.* at 50–52.

[121] A DARD, or Dispatchable Asset Related Demand is demand associated with an asset that can modify its energy consumption in response to dispatch instructions, in Real-Time. DARDs in the New England Control Area include the consumption side of pumped storage hydro facilities and grid-connected batteries.

resource is also receiving a Day-Ahead energy award for that same hour of the Operating Day.[122] The resource must have ten-minute ramping capability and meet the operating reserve eligibility requirements in Section III.1.7.19.1 of Market Rule 1.[123]

2. DA TMNSR

Generator Assets and DRRs are eligible to provide DA TMNSR provided they meet all of the requirements necessary to provide Real-Time TMNSR. This includes, as a general matter, being offline (*i.e.*, not spinning or synchronized), which in the context of the Day-Ahead Market means that the resource does not have a Day-Ahead energy award for the same hour of the Operating Day.[124] The resource must have the capability to synchronize to the grid within ten-minutes and meet the operating reserve eligibility requirements in Section III.1.7.19.1 of Market Rule 1.[125]

DARDs are not eligible to provide DA TMNSR for the simple reason that they are only able to provide reserves when "online." A DARD is demand associated with an asset that modifies its energy consumption in response to dispatch instructions. Just as in Real-Time operations, a DARD must be consuming energy in order to provide reserves because its ability to provide reserves is based on its ability to reduce its energy consumption if called upon to do so.[126] Because a DARD must be consuming to provide reserves, it must be cleared to be online and consuming energy during the award-hour in order to provide Day-Ahead reserve. Simply, just like in Real-Time, a DARD is not able to provide non-spinning reserves.[127]

3. DA TMOR

Generator Assets, DRRs, and DARDs are eligible to provide DA TMOR provided they meet all of the requirements necessary to provide Real-Time TMOR. DA TMOR, like Real-Time TMOR, can be provided from either an online or offline state. The resource must have thirty-minute ramping capability, and if provided from an offline resource, fast-start capability.

[122] *Id.* at 12–13.

[123] *Id.* at 25.

[124] *Id.* at 24–25. For clarification, there are instances in today's Real-Time reserve market where a resource can be both online and still receive a TMNSR designation. This happens when resources are composed of multiple generating units whose synchronized capability cannot be determined by the ISO. *See* Section III.1.7.19.2.1.1 of Market Rule 1. Effectively, the resource may have different generating units, some of which are synchronized and some of which are not. This will also be true with regard to DA TMNSR.

[125] *Id.* at 25.

[126] *See id.* at 24–25.

[127] *Id.*

The resource must also meet the operating reserve eligibility requirements in Section III.1.7.19.1 of Market Rule 1.[128]

4. DA EIR

Generator Assets and DRRs are eligible to provide DA EIR if they meet the following requirements. First, the resource must be able to meet the same 60-minute ramping requirements that apply for Day-Ahead energy awards.[129] Second, the resource cannot be constrained by transmission limitations, similar to the same requirement for operating reserves. This criteria is intended to ensure deliverability in Real-Time if needed.[130] Third, the resource must be either (1) scheduled for energy within the hour of the DA EIR award, or (2) be a fast-start resource, which is a resource with a combined notification and start-up time that does not exceed thirty minutes and Minimum Run Times and Minimum Down Times that do not exceed one hour.[131]

This means that a non-fast-start resource that is scheduled in the Day-Ahead Market to be offline during a given hour of the Operating Day will not be eligible to provide DA EIR for that hour. Excluding non-fast-start resources that are offline is a necessary result of a technical limitation of the MCE.[132] Adjusting the MCE to accommodate these offline resources for the purpose of allowing them to clear for DA EIR would require additional variables that would increase the complexity of the MCE's attempts to "solve the market" in each hour and would raise concerns about the ability to run the Day-Ahead Market within required timeframes.[133] Allowing these non-fast-start offline resources to participate as DA EIR would have limited value given (1) the opportunity of these resources to clear for DA energy and (2) the expectation that the introduction of the FER Demand Quantity into the market will result in closing today's "energy gaps" through increased DA energy clearing over the long-run. As a result, there is limited value in introducing this complexity into the MCE for the purpose of allowing offline, non-fast-start resources to clear for DA EIR.[134]

DARDs are also not eligible to provide DA EIR. DARD consumption is not factored into the Day-Ahead load forecast. As a result, a DARD's reduction in consumption does nothing to

[128] *Id.*

[129] *Id.* at 19, 26.

[130] *Id.* at 27.

[131] *Id.* at 26.

[132] *Id.*

[133] *Id.* at 26–27.

[134] *Id.*

contribute to satisfying the load forecast. Because of this, a DARD's reduction in consumption does not help to satisfy the FER Demand Quantity, and they may not provide DA EIR.[135]

5. Ineligibility of Virtual Transactions

Virtual transactions are not eligible to provide Day-Ahead Ancillary Services, either Day-Ahead Flexible Response Services or DA EIR. The purpose of the proposed Day-Ahead Ancillary Services market and its products is to provide a market-based mechanism for creating a reliable, NERC-compliant next-day Operating Plan that identifies which resources will be available to perform in Real-Time to cover the load forecast and to meet Real-Time operating reserve requirements. Virtual transactions, which exist only in the Day-Ahead Energy Market and are, by definition, not backed by physical resources, cannot represent MWh of energy that could be called on in Real-Time.[136] Simply, they cannot contribute to a reliable Operating Plan and cannot provide Day-Ahead Ancillary Services.[137]

6. Ineligibility of Imports

As is true for Real-Time Operating Reserves, imports are not eligible to provide Day-Ahead Flexible Response Services. The purpose of the Day-Ahead Flexible Response Services products is to create awards and financial obligations for resources that can also act as reserves in Real-Time, if not otherwise in-merit to produce energy in Real-Time (as explained above, likely due to Real-Time energy prices exceeding what was expected Day-Ahead).[138] Allowing imports to provide these products would be inconsistent with that purpose.[139]

Imports are also not eligible to provide DA EIR because it is currently infeasible to coordinate such a reserve transaction with neighboring control areas. For an import with a DA EIR award to be deliverable as energy in Real-Time, the ISO's neighboring systems would have to commit their resources Day-Ahead in a way that would allow those resources to function as reserves in Real-Time.[140] To do so would be difficult for a number of practical reasons. New York's day-ahead market is operated earlier than New England's Day-Ahead Market, which creates challenges for determining how those imports would be committed.[141] Quebec does not have an organized day-ahead market, and it is not clear how the DA EIR transaction would be

[135] *Id.* at 25.

[136] *Id.* at 28.

[137] *Id.* at 27–28.

[138] *See id.* at 28.

[139] *See id.*

[140] *Id.*

[141] *Id.* at 28–29.

coordinated between Quebec and New England.[142] The ISO is open to the possibility of allowing imports in the future to provide DA EIR, but that is contingent on coordination on market changes with the neighboring control areas, which would take considerable time and effort. Undertaking this effort now is not feasible.[143] And similar to the considerations regarding offline, non-fast-start resources' eligibility to provide DA EIR, such efforts may not provide much value if increased clearing of Day-Ahead energy in the new Day-Ahead Market over time results in little to no DA EIR being procured to satisfy the load forecast.[144]

It is worth noting that imports will continue to be allowed to clear for Day-Ahead energy subject to the same external transaction rules that exist today. Because of this, when imports do have a Day-Ahead energy award, they will contribute to satisfying the load forecast. As explained further below in Section V.H.3, imports therefore will receive both the Day-Ahead LMP and the FER Price for each MWh of their energy award. Imports will be required, however, to demonstrate a submitted corresponding Real-Time transaction to receive the FER Price.

E. Day-Ahead Ancillary Services Offer Mechanics

The Generator Assets, DRRs, and DARDs eligible to provide Day-Ahead Ancillary Services can submit offers in the same timeframe during which offers are due in the Day-Ahead Energy Market, which is before 10:30 a.m. on the day before the Operating Day and will remain unchanged from today. Offers will cover only one hour, meaning that the offer is to provide Day-Ahead Ancillary Services associated with a single hour of the Operating Day.

As mentioned above, to submit a Day-Ahead Ancillary Services Offer, the resource must submit an energy offer (Supply Offer for generators, Demand Reduction Offer for DRRs, or Demand Bids for DARDs) in the Day-Ahead market as well. Importantly, the resource's energy offer and its Offer Data will have the requisite physical parameters, such as ramp rates, minimum run times, minimum down times, CLAIM10 capability, CLAIM30 capability, and maximum operating limits, that the MCE will need to consider when clearing resources for different types of Day-Ahead reserves.[145] With all of these physical parameters relevant to reserve capability included in the energy offer, the Day-Ahead Ancillary Services Offer will require only that the resource specify the hour of the Operating Day for which the offer applies, non-negative offer

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[142] *Id.* at 29.

[143] *Id.*

[144] *See id.* Coordination with neighboring regions would be a multi-year process, and delaying the benefits of implementing DASI for what is likely to have little value to the system in the long-run would not be beneficial to the region. *See id.* at 27, 55–56 (explaining long-run convergence expected to eliminate Day-Ahead energy gap and need for DA EIR).

[145] *Id.* at 32.

prices for each of the Day-Ahead Ancillary Services products, and a single offer quantity representing the total MWh offered across all four products.[146]

The Day-Ahead Ancillary Services Offer will specify only one quantity value and allow four separate offer prices for each of the products. An offer does not need to specify a quantity for each product because the Day-Ahead MCE, using the physical parameters from the energy offers, will determine the optimal set of ancillary services the resource is able to provide, taking into account the resource's offer prices.[147] Offers do allow specification of different prices for each product to allow for potential variances in costs of providing each of the ancillary services.[148] The MCE will ignore any prices submitted for products that the resource is not eligible to provide.

Suppliers also have the option to submit a new parameter as part of their Day-Ahead Ancillary Services Offer—the Maximum Daily Award Limit ("MDAL"). The MDAL is a quantity that the resource can submit with its offer that reflects the maximum total MWh quantity of both Day-Ahead energy and Day-Ahead Ancillary Services that the resource is willing to sell across all 24 hours of the Day-Ahead Market horizon. This optional parameter is conceptually similar to the current Maximum Daily Energy Limit ("MDE") parameter that resources may submit to limit the amount of Day-Ahead energy they clear across all hours of the Day-Ahead Energy Market.[149] If no MDAL is submitted, no such limitation for the resource will be incorporated into the MCE. The ISO anticipates that batteries and pumped storage resources are the most likely to utilize the MDAL to reflect the limits of their energy storage capabilities throughout a single twenty-four hour period and their need to cycle in order to replenish stored energy.[150] MDAL also may be used by a supplier to limit the financial exposure that comes with Day-Ahead awards.[151]

The Day-Ahead Ancillary Services Market will not impose a must-offer requirement on the region's ancillary services providers. Although a must-offer requirement exists in the Day-Ahead Energy Market for suppliers that are awarded a Capacity Supply Obligation in the Forward Capacity Market, no such requirement is needed for suppliers in the Day-Ahead Ancillary Services Market. Day-Ahead Ancillary Services revenues will attract the participation from suppliers, and the ISO's design will result in clearing prices that will cover the offer prices they submit and, therefore, their expected costs of providing these ancillary services.[152]

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[146] *See id.* at 29–31.

[147] *Id.* at 33.

[148] *Id.* at 33–34.

[149] *Id.* at 31; *see also* Tariff, Section I.2.2.

[150] *Id.* at 31–32.

[151] *Id.* at 32.

[152] *See* White Testimony at 107–09 (explaining sufficient profit incentive to participate in market, and other factors). As described further in Section VI below, to the extent a supplier sees the potential for

Furthermore, a must-offer requirement is not a necessary tool to address physical withholding concerns, which as described further in Section VI.F below, will be addressed by new ancillary-services specific conduct-and-impact test thresholds.[153]

F. Offer Price Formulation

Consistent with designing a competitive market, the ISO has evaluated how suppliers are expected to formulate competitive offers for the new Day-Ahead Ancillary Services products. Consistent with competitive conditions, suppliers are expected to make offers reflective of the incremental costs of taking on a Day-Ahead Ancillary Services award. The three types of incremental costs that should inform suppliers' offer prices are potential close-out charges the supplier may incur, any fuel or energy-charging costs that the resource incurs as a result of taking on a Day-Ahead Ancillary Services award, and a risk premium that reflects the uncertainty of close-out charges, or other factors, that may impact the resource's ability to earn a profit by participating in the market.[154]

1. Expected Close-Out Charges

The first incremental cost—the potential close-out cost—is common to all resources taking on a Day-Ahead Ancillary Services award. As explained in Dr. Alivand's testimony, the expected close-out charge that resources will build into their offer prices will be the probability of different potential close-out charges, which is dependent on the probability of different potential Real-Time Hub Prices and the strike price announced by the ISO for the hour associated with the award.[155] Because all resources are subject to potential close-out charges, as a function of (1) potential Real-Time Hub Prices and (2) the strike price, all resources will need to factor their expectations of the close-out charge for any given award-hour in making an offer for that hour.[156]

Dr. Alivand provides a simplified example of how an expected close-out charge is calculated based on three potential, equally likely Real-Time Hub Prices, which result in three

offer mitigation to be a deterrent to its participation, the ISO has addressed those concerns in its mitigation design by (1) creating a data-driven conduct-and-impact test mitigation structure with a set of thresholds that will avoid unnecessary mitigation of competitive, cost-based offers and (2) adjusting its mitigation-related cost-recovery process to allow resources to seek to recover costs incurred during the rare circumstance under which a Day-Ahead Ancillary Services Offer is inappropriately mitigated.

[153] *Id.* at 109–11 (noting, also, EMM recommendation against must-offer requirement for mitigation purposes).

[154] Alivand Testimony at 29–32.

[155] *Id.* at 32–33.

[156] *Id.*

potential, equally likely expected close-out charges.[157] However, in application, expected close-out charges should be calculated using a model that takes into account a distribution of potential Real-Time Hub Prices. The ISO's GMM will calculate expected close-out charges for each award-hour. Rather than develop their own models, suppliers will be able to utilize the model results when formulating their offer prices.[158] The GMM-calculated expected close-out will be published daily and available to Market Participants. This expected close-out will also serve an important role in the ISO's mitigation structure for the Day-Ahead Ancillary Services Market, as described further below in Section VI.C.1. Suppliers are also able to develop or source their own expected close-out charge models.[159] Supplier-originated models can have a role to play in the proposed mitigation structure, subject to IMM review, also as described further below.

2. Avoidable Fuel or Charging Costs

The second incremental cost, which is not common to all resources taking on Day-Ahead Ancillary Services awards, is the cost associated with procuring fuel in advance of the Operating Day in order to be prepared to produce energy during the award-hour, or the cost associated with charging a storage resource in advance of the award-hour.[160] Importantly, only those fuel or charging costs that the resource would avoid but for taking on the Day-Ahead Ancillary Services award are expected to be accounted for in the Day-Ahead Ancillary Services offer price.[161]

Dr. Alivand provides an example of when the cost to procure natural gas day-ahead is an avoidable cost associated with the Day-Ahead Ancillary Services award and should be accounted for in a seller's offer price.[162] The example illustrates that the determination of when day-ahead gas procurement is an incremental or avoidable cost relies on the resource's expectations regarding whether it will clear for and profit from selling energy in Real-Time during the award-hour and whether such profit is greater when it procures gas day-ahead or intraday (*i.e.*, during the Operating Day).[163] Ultimately, if the resource would stand to earn greater profit from procuring gas day-ahead and selling energy when in-merit in Real-Time during the award-hour *independent* of any Day-Ahead Ancillary Services award for that hour, the incremental fuel cost associated with any Day-Ahead Ancillary Services award for that hour should be zero. If the resource would stand to earn greater profit from waiting and procuring gas intraday and selling energy when in-merit in Real-Time during the award-hour—thereby having no reason to procure gas day-ahead other than its need to cover a Day-Ahead Ancillary Services award during the

[157] *Id.* at 33–35.

[158] *Id.* at 36–37.

[159] *See id.*

[160] *Id.* at 31–32, 37–38.

[161] *See id.* at 38–40, 46.

[162] *See id.* at 40–49 (providing example and counter-example).

[163] *See id.*

award-hour—then the cost of procuring gas day-ahead functions as a positive incremental cost associated with the award and would be built into the offer price.[164]

The incremental cost associated with storage resources, such as pumped hydro and batteries, requires similar considerations. The decision to charge energy for later discharge during the award-hour should be one that depends on, and thereby could be avoided without taking on, the Day-Ahead Ancillary Services award.[165] For storage resources, this cost will be a function of electricity prices. Namely, it will be a function of (1) electricity prices during the period of charging and (2) expected electricity prices during the award-hour compared to other potential discharge hours.[166] It will also be a function of the roundtrip efficiency of the resource.[167] Ultimately, as with resources making fuel procurement decisions, the cost of charging will function as a positive incremental cost associated with the Day-Ahead Ancillary Services award if the resource would not have incurred (*i.e.*, could have avoided) the charging cost but for the award.[168]

Resources of technology types other than natural gas-fired or storage resources are not expected to have incremental fuel costs associated with their Day-Ahead Ancillary Services awards.[169] This reflects the nature of how resource types like oil resources incur fuel costs.[170] The region's oil resources procure and store fuel well in advance of the Day-Ahead timeframe, usually to cover energy production for a week or more, or for an entire season.[171] Consequently, the cost of oil procurement is independent of any specific Day-Ahead Ancillary Services award and functions as a sunk cost that would not have been avoided without such an award.[172] Moreover, unlike natural-gas resources that must schedule fuel delivery for use on a specific day, oil resources do not have to use their fuel within a specific timeframe. If oil resources do not use their fuel during the award-hour, the fuel can still be used to produce energy and earn energy revenues in a future hour.[173] Thus, even if a resource were to designate a certain amount of oil as available to cover a Day-Ahead Ancillary Services award-hour, the cost of that oil remains

[164] *Id.* at 46, 48–49 (illustrating avoidable input cost calculation for example and counter-example).

[165] *Id.* at 51.

[166] *Id.* at 51–53.

[167] *Id.* at 52.

[168] *See id.* at 51–53.

[169] *Id.* at 37–38, 49–50.

[170] *Id.* at 49–50.

[171] *Id.* at 50.

[172] *Id.* at 49–50.

[173] *Id.* at 50.

recoverable when it is ultimately used to produce energy in a different hour or on a different day.[174]

Finally, operating and maintenance ("O&M") costs beyond the avoidable fuel or charging costs noted here should not be part of competitive Day-Ahead Ancillary Services Offers.[175] Non-fuel O&M costs are generally costs that are only incurred as part of producing and delivering energy and reflected in a resource's energy offer. That is, they are costs incremental to producing energy and not incremental to preparing to produce energy during the award-hour, or avoidable but for the Day-Ahead Ancillary Services award. Nevertheless, the ISO recognizes that there may be specific resources that would incur staffing and other O&M costs to prepare to produce energy during the award-hour, and they would only do so because of a Day-Ahead Ancillary Services award and not because they expect to produce energy in Real-Time for that same award-hour. Suppliers may end up building these resource-specific costs into their offers, and for mitigation purposes as explained further below in Section VI.D, consult with the IMM about any impact such costs may have on submitting offer prices within mitigation threshold limits.

3. Risk Premiums

The third cost component of a competitive Day-Ahead Ancillary Services Offer is the risk premium. Resources selling Day-Ahead Ancillary Services products face uncertainty regarding the costs of an award, both in terms of close-out charges and avoidable fuel or charging costs, and face a financial risk that such costs will be higher than predicted.[176] To account for this risk, the ISO expects suppliers to build risk premiums into their offer prices to reflect this financial risk.[177] Not all suppliers will incorporate risk premiums, as some may balance the cost of uncertainty against the fact that Day-Ahead Ancillary Services revenues are a new revenue stream that decrease some of the financial risks associated with participating in the ISO's energy markets.[178]

G. Day-Ahead Awards and Clearing Prices (including Penalty Factors)

The Day-Ahead Ancillary Services Offers and new demand quantities will be reflected in constraints in the MCE for the proposed joint Day-Ahead Market, along with suppliers' energy offers, demand bids by load, and other parameters and constraints necessary for the proper clearing and pricing of energy and ancillary services awards in the Day-Ahead Market.[179] The

[174] *Id.*

[175] *See id.* at 53.

[176] *Id.* at 53–54.

[177] *Id.*

[178] *Id.* at 54–55.

[179] Ewing Testimony at 35–36.

proposed Day-Ahead MCE will clear offers and demand (as in bid-in demand and demand quantities) for both Day-Ahead energy and ancillary services jointly to optimize the allocation of energy and ancillary services awards—that is, solve for the most cost-effective allocation of resources across all Day-Ahead products in light of resource offer prices and reserve capability.[180] As mentioned above and explained in further detail in Mr. Ewing's testimony, the MCE will consider the physical parameters reflecting the reserve capabilities of resources offering Day-Ahead Ancillary Services when determining the Day-Ahead energy and ancillary services awards.[181] This type of joint optimization across Day-Ahead products is similar to the joint optimization of the Real-Time MCE across energy and operating reserve products and is effectively the same joint optimization process that occurs in many other regions' Day-Ahead markets.[182]

Ultimately, the MCE for the proposed joint Day-Ahead Market will result in a schedule of awards for both Day-Ahead energy and Day-Ahead Ancillary Services and four new clearing prices: the DA TMSR clearing price, the DA TMNSR clearing price, the DA TMOR clearing price, and the FER Price. The Day-Ahead Flexible Response Services clearing prices will be determined based on the clearing of Day-Ahead Ancillary Services Offers against demand quantities and marginal cost pricing principles, consistent with the "cascading" of operating reserve products that currently occurs with Real-Time Operating Reserves today.[183] Namely, as Mr. Ewing explains in his testimony, each Day-Ahead Flexible Response Services clearing price will reflect the shadow prices associated with each demand quantity that is satisfied by the product, consistent with how Real-Time Operating Reserve prices are determined today and with the participation payment principle.[184] The Day-Ahead Flexible Response Services clearing prices will be paid to their respective products: the DA TMSR clearing price to DA TMSR awards, the DA TMNSR clearing price to DA TMNSR awards, and the DA TMOR clearing price to DA TMOR awards.

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[180] *Id.* at 36.

[181] *Id.* at 36–41.

[182] *Id.* at 42.

[183] *Id.* at 43.

[184] As Mr. Ewing explains, a product must be paid the shadow prices of each constraint (*i.e.*, demand quantity) that the product contributes to satisfying because the shadow prices are the value that the product provides to the system at the margin by satisfying the constraint. *Id.* at 44–45 (referring to this as the "participation payment principle"). For example, because DA TMSR can contribute to satisfying all four of the Day-Ahead Flexible Response Services Demand Quantities, the DA TMSR clearing price paid to resources with DA TMSR awards will be the sum of the shadow prices for all four Day-Ahead Flexible Response Services Demand Quantities. *Id.* at 45–46. Again, this the same pricing methodology the ISO's Real-Time MCE currently employs when pricing Real-Time Operating Reserves. *Id.* For an illustration of how reserve prices are determined using shadow prices, please see pages 46 through 49 of Mr. Ewing's testimony.

The FER Price is the price that will be paid to Day-Ahead energy awards to physical (*i.e.*, non-virtual) supply resources and DA EIR awards. As a result, there is no separate clearing price for DA EIR; the FER Price serves as the DA EIR clearing price. Physical resources with Day-Ahead energy awards are paid both the applicable Day-Ahead LMP, as they are under today's market rules, and the FER Price. The FER Price, like all other Day-Ahead prices, will be determined in accordance with marginal cost pricing principles, reflecting the marginal cost and marginal benefit of satisfying the FER Demand Quantity.[185]

As Mr. Ewing explains, the FER Price will ultimately be determined by the marginal cost to the region of clearing an additional MWh of physical energy (which also would include satisfying additional bid-in demand) or clearing an additional MWh of DA EIR.[186] The cost would reflect the marginal cost of DA EIR (reflecting expected close-out costs, avoidable fuel or charging costs, and risk premium of the marginal supplier) or the marginal cost of clearing additional physical energy, which would—as reflected in the example provided in Mr. Ewing's testimony—be net of any benefit gained by satisfying an additional MWh of bid-in demand.[187] Ultimately, as a result, the FER clearing price is expected to be much lower than Day-Ahead LMPs.[188] In many hours, namely, those where physical energy clears against bid-in demand and in an amount that equals or exceeds the load forecast, the FER Price is expected to be zero.

All Day-Ahead clearing prices—Day-Ahead LMPs, Day-Ahead Flexible Response Services Prices, and the FER Price—will, by nature of the MCE's joint optimization, incorporate cross-product opportunity costs.[189] As described above, the MCE's joint optimization process takes into account the relative energy and ancillary services offers and reserve capabilities of each resource when "solving" the Day-Ahead Market (that is, clearing supply against demand). It does not consider each Day-Ahead product's supply offers and demand in isolation but rather seeks to determine the optimal set of Day-Ahead awards that maximizes the efficient use of resources. Put differently, the Day-Ahead MCE seeks the most cost-effective solution across all products as a whole. As a result, a resource might be financially better off providing one Day-Ahead product, but receive an award for a different Day-Ahead product because the MCE's optimization process seeks the most economically efficient solution.[190] In such a circumstance, and in the absence of MCE pricing that accounts for this, the resource would experience an opportunity cost associated with its award.[191]

[185] *Id.* at 52.

[186] *See id.* at 52–53.

[187] *See id.* at 50–52, 54–55.

[188] *See id.* at 53–54.

[189] *Id.* at 58–60.

[190] *See id.* at 57–59.

[191] *See id.* at 57–58.

To address this, the Day-Ahead MCE will incorporate such opportunity costs into the clearing prices for the Day-Ahead energy and ancillary services products. The inclusion of opportunity costs is important to ensure that suppliers remain indifferent between clearing for one Day-Ahead product over another and to avoid creating an incentive for suppliers to submit offer prices inconsistent with their costs in an attempt to clear for a "more profitable" product.[192] The inclusion of cross-product opportunity costs in the Day-Ahead clearing prices is no different than the inclusion of such cross-product opportunity costs in the ISO's Real-Time energy and Operating Reserve clearing prices.[193] Simply, the Day-Ahead clearing prices will reflect marginal costs—including incremental and cross-product opportunity costs—in a way that is consistent with the ISO's Real-Time market clearing practices, similar practices in other region's Day-Ahead markets, and sound market design principles.[194]

Finally, the ISO will incorporate into the Day-Ahead MCE Reserve Constraint Penalty Factors ("RCPFs") and an analogous FER Penalty Factor, which will collectively establish the maximum cost the region is willing to incur to satisfy the Day-Ahead Flexible Response Services Demand Quantities and the FER Demand Quantity. The Day-Ahead MCE will incorporate the RCPFs currently applied to each of the Real-Time Operating Reserve requirements and apply them to each Operating Reserve requirement's Day-Ahead analog. The ISO chose the same RCPFs as apply in Real-Time to ensure consistent pricing between Day-Ahead and Real-Time energy and avoid creating perverse participation incentives that could result in divergence of the two energy markets.[195]

As such, the RCPFs that will apply in the Day-Ahead Market are the following:

- for the Day-Ahead Ten-Minute Spinning Reserve Demand Quantity, $50/MWh;
- for the Day-Ahead Total Ten-Minute Reserve Demand Quantity, $1,500/MWh;
- for the Day-Ahead Minimum Total Reserve Demand Quantity, $1,000/MWh; and
- for the Day-Ahead Total Reserve Demand Quantity, $250/MWh.

As they do in Real-Time, the RCPFs will set the shadow prices of any violated constraint, that is, any demand quantity that cannot be met by available reserve capabilities.[196] And similar again to

[192] *See id.* at 58.

[193] *See id.* at 57–58.

[194] *See id.* at 58; *cf. PJM Interconnection, L.L.C.*, 173 FERC ¶ 61,123 at P 20 (2020) ("As a general matter, a system that jointly optimizes dispatch of energy and reserves should reflect the opportunity costs of providing reserves instead of energy."); *PJM Interconnection, L.L.C.*, 153 FERC ¶ 61,289 at P 38 n.52 (2015) ("The Commission has found it appropriate to reflect opportunity costs in PJM's market clearing price."). Mr. Ewing provides an example of how cross-product opportunity costs are considered by the Day-Ahead MCE. Ewing Testimony at 60–61.

[195] *Id.* at 65.

[196] *Id.* at 62–64.

what occurs today in Real-Time, these RCPFs may be incorporated within and serve as an "adder" to the Day-Ahead LMP.[197] Mr. Ewing provides examples of how RCPFs can set shadow prices and become incorporated into the Day-Ahead LMP.[198]

The FER Penalty Factor will be set at $2,575/MWh, which represents approximately 101 percent of the sum of the relevant RCPFs ($2,550/MWh) above.[199] The ISO set the FER Penalty Factor at a level slightly higher than the sum of these RCPFs to ensure that a violation of the FER Demand Quantity is more costly than simultaneous violations of the Day-Ahead Flexible Response Services Demand Quantities.[200] The purpose is to ensure that the Day-Ahead MCE prioritizes satisfying the FER Demand Quantity (*i.e.*, the load forecast) over satisfying the Day-Ahead Flexible Response Services Demand Quantities (*i.e.*, the Day-Ahead ten- and thirty-minute reserve requirements), because serving load is more important that fully satisfying the demand for reserves.[201]

H. Settlements and Cost Allocation

As explained above, the proposed Day-Ahead Ancillary Services Market includes a two-settlement structure for Day-Ahead Ancillary Services suppliers: (1) credits for Day-Ahead Ancillary Services awards, which will be calculated based on the quantity of the awards multiplied by the applicable Day-Ahead Ancillary Services product's clearing price; and (2) a close-out charge whenever the actual Real-Time Hub Price exceeds the strike price, in an amount set at the difference between the two, multiplied by the quantity of Day-Ahead Ancillary Services awards.[202] Beyond this, settlements and cost allocation differ depending on whether the Day-Ahead Ancillary Services award is for a Day-Ahead Flexible Response Service product or DA EIR. FER credits paid to suppliers with Day-Ahead energy awards also have distinct settlement and cost allocation rules.

1. Supplier Credits and Charges Related to All Day-Ahead Ancillary Services

Suppliers with awards for Day-Ahead Ancillary Services products (*i.e.*, DA TMSR, DA TMNSR, DA TMOR, and DA EIR) receive credits at Day-Ahead Ancillary Services clearing prices and close-out charges when the Real-Time Hub Price exceeds the strike price. Mr. Ewing provides an example of a supplier's credits and close-out charges for Day-Ahead Ancillary

[197] *See id.* at 64–65.

[198] *Id.* at 63–65.

[199] *Id.* at 65–66.

[200] *Id.*

[201] *Id.* at 66.

[202] As noted above, the close-out charge is set to "zero" whenever the Real-Time Hub Price is equal to or less than the strike price.

Services awards for DA TMNSR and DA EIR.[203] Importantly, the DA EIR clearing price is the FER Price.

2. Charges and Credits to Load Related to Day-Ahead Flexible Response Services

Day-Ahead Flexible Response Services credits to suppliers will be charged on a pro-rata basis to certain load with Real-Time Load Obligations ("RTLO"). This reflects a beneficiary pays approach to cost allocation and is modeled on the cost allocation for Real-Time Operating Reserves credits.[204] The rationale for adopting the same cost allocation approach as for Real-Time Operating Reserves is that both the Day-Ahead and Real-Time reserves products enable the region to be prepared to maintain reliability in the event of a large Real-Time source-loss contingency.[205]

The RTLO to which credits will be charged will be all RTLO incurred at nodes internal to the New England Control Area, except for RTLO incurred by Storage DARDs. Because operating reserves are not procured for the benefit of the consumption of price-sensitive demand—which is what Storage DARDs represent—Storage DARDs are not charged for Real-Time Operating Reserves costs and also will not be charged for Day-Ahead Flexible Response Services costs.[206] In fact, if a contingency were to occur in Real-Time, Storage DARDs would be expected to reduce their consumption.[207]

The RTLO to which credits will be charged excludes RTLO at External Nodes, with the exception of RTLO associated with Capacity Exports Through Import Constrained Zones ("CETICZ") Transactions and Forward Capacity Auction ("FCA") Cleared Export Transactions, which will be charged. Although operating reserves are not generally procured to support the continued flow of External Transactions, CETICZ and FCA Cleared Export Transactions are exceptions. These two types of exports are considered "supported in real-time" and incorporated into the planning of resource commitments so that they are treated more comparably to "native load."[208] These resources do benefit from the procurement of operating reserves, and as with Real-Time Operating Reserves, RTLO associated with these types of exports will be charged Day-Ahead Flexible Response Services costs.[209]

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[203] *Id.* at 67–68.

[204] *Id.* at 70.

[205] *Id.*

[206] *Id.* at 71.

[207] *Id.*

[208] *Id.* at 71–72.

[209] *Id.*

The total close-out charges to suppliers of Day-Ahead Flexible Response services are credited back to the same RTLO on a pro rata basis that incurred charges from the sellers' Day-Ahead Flexible Response Services credits. This, again, reflects the beneficiary pays approach to allocation of the costs of the awards.[210]

3. Supplier Credits Related to the FER

Suppliers with awards for Day-Ahead energy for Generator Assets or DRRs will receive a FER credit, which will equal the MWh of the energy award multiplied by the FER Price. As discussed above, DARDs and virtual transactions are not eligible to receive FER credits because they do not contribute to satisfying the FER Demand Quantity (*i.e.*, the load forecast).

Suppliers clearing imports in the Day-Ahead Energy Market are eligible to receive FER credits for their Day-Ahead energy awards provided that the supplier properly submits a corresponding Real-Time Energy Market transaction for the same MWh as the Day-Ahead energy award and also submits a corresponding transaction in the appropriate neighboring Control Area.[211] The formal settlement rule is that an import will only be paid the FER Price on the lesser of the MWh of the Day-Ahead energy award and the MWh of the corresponding transaction submitted in the Real-Time Energy Market.

This settlement rule provides imports the proper incentive to ensure they are scheduled in Real-Time. Under current market rules, an import that clears in the Day-Ahead Energy Market must also submit a corresponding transaction in the Real-Time Energy Market in order to be scheduled in Real-Time.[212] If the supplier does not submit the corresponding Real-Time transaction, then the import cannot be scheduled in Real-Time and does not contribute to satisfying the load forecast.[213] Conditioning FER payments on the submission of a Real-Time transaction maintains the incentive for imports to ensure they are able to be scheduled in Real-Time.[214] A similar rule is not required for Generator Assets or DRRs because their energy offers are automatically carried forward from the Day-Ahead Market to the Real-Time market.[215]

4. Charges to Load Related to the FER and DA EIR

The sum total of FER and DA EIR credits to suppliers will be charged to load on a cost causation and beneficiary pays basis as follows. First, all Day-Ahead cleared export transactions are charged for their Day-Ahead cleared energy MWh quantity at the FER Price. The reason for

[210] *See id.* at 70, 73.

[211] *Id.* at 68–69.

[212] *Id.* at 69.

[213] *Id.*

[214] *Id.*

[215] *Id.*

this direct charge is because, for every MWh of cleared export, an additional MWh of physical supply must be procured.[216] This results in an increase in FER costs at the FER Price that, as a matter of cost causation, should be charged to the cleared export.[217]

Second, the remainder of the FER and DA EIR credits will be charged, on a pro-rata basis, to RTLO incurred at nodes internal to New England, except for RTLO incurred by Storage DARDs. This reflects a beneficiary pays approach to cost allocation, as the FER Demand Quantity, representing the load forecast, is applied for the benefit of "firm" Real-Time load internal to New England, and Real-Time "firm" load accrues the reliability benefits of procuring resources sufficient to cover the load forecast.[218] As explained above, Storage DARD consumption is not reflected in the load forecast; thus, Storage DARDs do not benefit from satisfying the FER Demand Quantity.[219]

5. Credits to Load Related to DA EIR

Finally, the total close-out charges to suppliers of DA EIR are credited back to the same RTLO on a pro rata basis that incur charges for sellers' FER credits and DA credits. This, again, reflects the beneficiary pays approach to allocation of the costs of the DA EIR awards.[220]

I. Retirement of the Forward Reserve Market

As part of DASI, the Filing Parties propose retiring the FRM. The proposed implementation date for the new Day-Ahead Ancillary Services Market is March 1, 2025, and the ISO intends to shorten the final Forward Reserve Procurement Period such that it ends on February 28, 2025. The ISO proposed the FRM's retirement because the FRM, as currently designed, is incompatible with the proposed Day-Ahead Ancillary Services Market.[221]

For background, the FRM is a market that provides a seasonal forward payment to Market Participants with reserve capable resources. The FRM procures forward obligations for Real-Time TMNSR and TMOR, with the requirements for both set based on historically observed first and second contingencies.[222] In exchange for taking on a Forward Reserve Obligation, participants must offer an associated energy quantity into the Day-Ahead and Real-Time Energy Markets at or above an ISO-determined price known as the Forward Reserve

[216] *Id.* at 72.

[217] *Id.*

[218] *Id.* at 72–73.

[219] *Id.*

[220] *Id.* at 73.

[221] *Id.* at 76.

[222] *Id.* at 74.

Threshold Price ("FRTP").[223] The energy offers must be made only for hours that fall within the period from hour ending 0800 to hour ending 2300 for each weekday, excluding those weekdays that are defined as NERC holidays.[224] The requirement to offer energy above the FRTP in certain hours decreases the likelihood that an FRM resource will be dispatched for energy during those hours, and thereby increases the chance the resource will provide reserves during those hours.[225]

Despite procuring ancillary services ahead of Real-Time, the FRM differs from the proposed Day-Ahead Ancillary Services Market in many important ways.[226] First, the FRM considers only a subset of operating reserve requirements and does not procure TMSR. Second, the FRM has no explicit tie to securing the reserves that the ISO projects will be needed for each hour of the Real-Time Operating Day or to creating a reliable next-day Operating Plan; rather, it relies on observed historical operating needs. Third, the FRM applies only to a subset of hours on non-holiday weekdays. Overall, the FRM, unlike DASI, makes no attempt to value, in a targeted way, the reserve capabilities that the ISO projects the region will need for each hour of every Operating Day.

Maintaining the FRM at the same time as implementing DASI risks a number of issues. First, there is the risk that resources will receive double compensation for providing the same reserve capabilities.[227] Second, maintaining both the FRM and the proposed Day-Ahead Ancillary Services Market risks dividing resources' participation between the two markets. Both markets expose participants to financial risks associated with non-performance.[228] In the FRM, that financial exposure comes from Forward Reserve Failure-to-Activate Penalties, Forward Reserve Failure-to-Reserve Penalties, and Forward Reserve Obligation Charges. In the Day-Ahead Ancillary Services Market, the financial exposure comes from the close-out charge. Rather than incur the financial risks associated with non-performance in both markets, a supplier might choose one market over another, reducing the supply in both markets.[229] Such a supply reduction in both markets could reduce the competitiveness of each and increase the ability to exercise market power in either.[230]

[223] *Id.*

[224] *Id.*

[225] *Id.*

[226] *Id.* at 74–76.

[227] *Id.* at 77.

[228] *Id.* at 77.

[229] *Id.* at 77–78. The supplier may choose the market that it perceives has less onerous consequences for non-performance. *Id.*

[230] *See id.* at 78.

Moreover, the FRM—independent of any comparison to the Day-Ahead Ancillary Services Market—has other issues associated with it. The FRM, by requiring certain resources to offer energy above the FRTP, has the potential to distort Real-Time energy offers and may, in turn, result in higher-than-necessary energy prices in the event that such resources must be dispatched to provide energy.[231] The ISO's EMM has raised concerns about the FRM's impact on Real-Time energy offers and prices, and it has recommended the FRM's retirement.[232] The IMM has raised concerns about the potential exercise of market power in the FRM, which, notably, does not have a market power mitigation structure similar to the one being proposed for the Day-Ahead Ancillary Services Market.[233]

The ISO intends to propose an offer cap and other adjustments to the FRM to address the IMM's immediate market power concerns in the market. Yet, further addressing the FRM's incompatibility with the proposed Day-Ahead Ancillary Services Market, its potential distortionary effect on energy prices, or the EMM's other concerns with the market would require a considerable redesign of the FRM that would tie up valuable ISO resources. The ISO does not see any value in such a redesign effort. The proposed Day-Ahead Ancillary Services Market has been designed to provide the incentives necessary to compensate resources for the reserve capabilities they provide in a way that is more precisely tied to the needs of the region. The ISO is open to considering a new long-forward market for reserves in the future. However, any such market would have to be designed to work smoothly and compatibly with the Day-Ahead Ancillary Services Market, and experience with the operation of this new market would be necessary before any such design effort should be considered.[234] Further, the ISO would have to consider the value of pursuing a new long-forward market relative to other potentially more valuable reserve market designs, such as the addition of longer-duration reserves to the Day-Ahead and Real-Time markets, which may take priority in response to evolving system conditions.[235] In light of the above, the ISO is proposing to eliminate the FRM.

VI. PROPOSED MARKET POWER MITIGATION FOR DAY-AHEAD ANCILLARY SERVICES MARKET

The Filing Parties also propose market power mitigation rules for the new Day-Ahead Ancillary Services Market. The proposed mitigation rules are the product of a comprehensive Market Power Assessment ("MPA"), described in Section VI.A, pursuant to which the ISO identified any market power risks inherent in the proposed Day-Ahead Ancillary Services Market and designed a mitigation structure to address those risks. The MPA is described in

[231] *Id.* at 76.

[232] *See id.* at 78 (highlighting EMM's statements recommending the ISO consider retiring FRM).

[233] *See* ISO New England Internal Market Monitor, *Spring 2023 Quarterly Markets Report*, at 43 (Aug. 1, 2023), *available at* https://www.iso-ne.com/static-assets/documents/2023/08/2023-spring-quarterly-markets-report.pdf.

[234] *See* Ewing Testimony at 79.

[235] *Id.*

considerable detail in Dr. Alivand's testimony. The Filing Parties are not proposing any changes to its existing market power mitigation rules related to its Day-Ahead or Real-Time Energy Markets, with the exception of minor adjustments to the ISO's mitigation-related cost-recovery process that are necessary to accommodate the inclusion of the Day-Ahead Ancillary Services Market in that existing process. Rather, the market power mitigation rules are designed to ensure the Day-Ahead Ancillary Services Market remains an efficient and competitive one by striking a balance between over-mitigation and under-mitigation of Day-Ahead Ancillary Services Offers.

At a high-level, the proposed market power mitigation rules are as follows. The ISO has developed a conduct-and-impact test market power review and mitigation structure to address economic withholding.[236] This structure functions as *ex ante* mitigation for the Day-Ahead Market, meaning that it applies during the run of the Day-Ahead Market and impacts market outcomes. In this way, the new mitigation rules for Day-Ahead Ancillary Services Offers mirror the existing rules that apply in the energy markets for Supply Offers, which generally employ a conduct-and-impact test structure and are also implemented on an *ex ante* basis.

The conduct test consists of a price threshold above which a supplier's Day-Ahead Ancillary Services Offer is flagged as being uncompetitive because it does not reflect the supplier's costs of taking on a Day-Ahead Ancillary Services award. The ISO will determine a conduct test threshold for each resource for each offer-hour (*i.e.*, hour associated with the Day-Ahead Ancillary Services Offer). Conduct test thresholds will be calculated using a formula that allows offer prices based on a resource's costs, which—as described in Section V.F above—include expected close-out costs, avoidable fuel or charging costs, and risk premiums.

The impact test threshold consists of a threshold above which offers that failed the conduct test are then flagged as raising clearing prices above competitive levels. If the impact test threshold is violated, offer prices that violated conduct test thresholds are then mitigated down to ISO-estimated, cost-based offer prices, referred to as the Day-Ahead Ancillary Services Benchmark Levels (hereinafter "Benchmark Levels"). The market is then cleared and Day-Ahead awards are scheduled using these mitigated offer prices. The conduct-and-impact test for economic withholding, including the formulas for determining conduct test thresholds and impact test thresholds, are described below in Section VI.C. Relevant to the functioning of this proposed conduct-and-impact test are the changes to the existing IMM-consultation process and mitigation-related cost-recovery process that will make both processes applicable to the new Day-Ahead Ancillary Services Market. These revisions are discussed in Sections VI.D and VI.E.

[236] By way of background, economic withholding involves pricing some or all segments of an offer such that the offer or offer segment cannot (or is exceedingly unlikely) to clear the market. Physical withholding involves refusing to offer some or all of a product or service into the market. Although economic withholding and physical withholding in order to exercise market power have the same market impacts, the ISO has developed separate conduct tests to address the two different methods of withholding.

Moreover, the Filing Parties propose conduct-and-impact test thresholds to guide the IMM's inquiries into incidences of physical withholding of Day-Ahead Ancillary Services. As with the current physical withholding rules that apply to the ISO's energy markets, reviews for physical withholding will occur after the run of the Day-Ahead Market, serving as an *ex post* form of market power review and mitigation. The IMM's inquiry will be guided by a proposed conduct test threshold specifically for withholding of Day-Ahead Ancillary Services capabilities, and, to the extent necessary, the IMM will employ the same proposed impact test that will be employed for identifying economic withholding. The physical withholding conduct-and-impact thresholds, as well as the role of the IMM consultation process with regard to physical withholding inquiries, are discussed in Section VI.F below.

A. Market Power Assessment

The ISO designed and conducted its MPA with the goal of determining the potential for the exercise of market power within the proposed Day-Ahead Ancillary Services Market, and to then use those identified risks as a basis for designing a set of market-power mitigation rules. The MPA relied on a simulation of the proposed jointly-optimized Day-Ahead Market, including the proposed Day-Ahead Ancillary Services Market. The ISO used existing market data from the years 2016 through 2021 to create market simulations of those years, and thereby determined the days on which ancillary services suppliers would most likely have the ability to exercise market power and raise prices.[237]

The ISO identified 46 such days ("study days") from the 2016 to 2021 period: 31 of those days were days on which a pivotal supplier for ancillary services existed in the simulated Day-Ahead Market and 15 of those days were days that showed tight conditions for the energy markets.[238] Across the 46 study days, the ISO ran numerous and varied withholding scenarios to determine when attempts at withholding would impact Day-Ahead energy or Day-Ahead Ancillary Services prices in a way that would harm the overall competitiveness of the Day-Ahead Market. The withholding simulations included a study of the price impacts when the largest suppliers of Day-Ahead Ancillary Services withheld portions of their ancillary services capabilities in 10 percent increments, ranging from 10 to 100 percent withholding.[239] Also included were simulations of the largest suppliers of Day-Ahead Ancillary Services withholding 200 MW, 400 MW, and 600 MW of their capabilities.[240] As Dr. Alivand describes in his testimony, further withholding strategies were simulated, including simulations that assessed the

[237] Alivand Testimony at 56.

[238] *Id.* at 57–58. In his testimony, Dr. Alivand describes further the criteria used by the ISO to identify pivotal supplier days and tight condition days for purposes of the MPA. *Id.*

[239] *Id.* at 59–61. For the purpose of defining the largest suppliers, the MPA considered a Market Participants portfolio of resources, not just individual resources. *Id.*

[240] *Id.*

impact of withholding Day-Ahead energy capacity on Day-Ahead Ancillary Services prices.[241] Each simulation studied price impacts and the profitability of withholding for the suppliers for whom withholding was modeled.[242]

The ISO made six key findings as a result of the MPA. First, pivotal suppliers in the jointly optimized Day-Ahead Market will be infrequent. Second, the ability to materially raise Day-Ahead energy prices by withholding Day-Ahead Ancillary Services capability will be infrequent. Third, under certain infrequent conditions absent mitigation, a large supplier could profitably raise Day-Ahead Ancillary Services prices by withholding Day-Ahead Ancillary Services capability. Fourth, predicting hours during which withholding results in increased prices, and thus presents a profitable strategy for the withholding supplier, will be difficult. Fifth, under certain highly infrequent conditions absent mitigation, a large supplier could profitably raise Day-Ahead prices by withholding its total energy and ancillary services capabilities. Sixth, the price impacts of withholding Day-Ahead Ancillary Services occur primarily to Day-Ahead Flexible Response Services clearing prices, and not Day-Ahead energy prices or the FER Price. These findings and the data observed supporting these findings, which are detailed further in Dr. Alivand's testimony, underpin the ISO's proposed design for its market power mitigation structure.[243]

Overall, the ISO determined that the risk of harm from exercises of market power in the Day-Ahead Ancillary Services Market is small, though cannot be ignored.[244] Price increases from withholding Day-Ahead Ancillary Services capability on the whole were both rare and small, and extreme price increases were even rarer.[245] Price increases when a supplier engaged in withholding were also somewhat unpredictable.[246] On a tight day, 40-percent withholding by the largest Day-Ahead Ancillary Services supplier resulted in a price increase for DA TMNSR and DA TMOR clearing prices that was greater than $70/MWh in two hours. Yet, on the following day which had similarly tight market conditions, the same simulated withholding strategy resulted in a price *decrease* for both products that exceeded $45/MWh in one hour.[247]

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[241] *Id.*

[242] *Id.* As Dr. Alivand also explains, the MPA did not distinguish between physical and economic withholding. There is no difference in market impacts when withholding occurs as a result of uncompetitively high offer prices that ensure that an offer will not clear the market and when withholding occurs as a result of simply refusing to make an offer at all. *Id.* at 61. Further details of how the ISO designed and conducted the MPA are set forth in Dr. Alivand's testimony. *Id.* at 61–63.

[243] *Id.* at 63–76 (detailing the six findings and data observed supporting the findings). Examples of price impacts from simulations are provided in Dr. Alivand's testimony.

[244] *See id.* at 76–77.

[245] *See, e.g. id.* at 63, 66–72 (discussing second and third findings).

[246] *Id.* at 72–74.

[247] *Id.*

The rarity and unpredictability of successful withholding strategies is likely attributable to two factors. First, the region currently has a sufficient supply of resources that can provide Day-Ahead Ancillary Services.[248] Second, the joint Day-Ahead MCE, when finding the optimal clearing of the market, is prone to substitute the MWh withheld by one resource with the MWh offered by an alternative resource. Dr. Alivand explains the circumstances under which this type of substitution can arise.[249]

The ISO ultimately concluded, based on the MPA results, that (1) it was necessary to design a mitigation framework to address the rare hours during which market power is a concern and (2) the design must strike a careful balance between over-mitigation and under-mitigation of Day-Ahead Ancillary Services Offers, given that market power concerns are not pervasive or frequent.[250]

B. Conduct-and-Impact Test Rationale

The ISO proposes a conduct-and-impact test mitigation structure to help identify and mitigate potential exercises of market power through the Day-Ahead Ancillary Services Market. The ISO chose to design a conduct-and-impact test because, as a general matter, this type of test focuses on Market Participant behavior, rather than structural concerns with the market.[251] The MPA simulations showed that the existence of a pivotal supplier in the Day-Ahead Market was rare (only 0.22 percent of hours studied across 2016 to 2021) and that withholding infrequently raised clearing prices in a meaningful way on those days.[252] The maximum price increases in Day-Ahead clearing prices in the MPA simulations occurred on days without a pivotal supplier.[253] Consequently, the ISO determined that a pivotal supplier test, or other structural test, was neither necessary nor appropriate, as it would have the potential to over-mitigate offers on some days and under-mitigate offers on other days.[254] A conduct-and-impact test on the other hand, which screens for uncompetitive offers and focuses on such offers' market impacts, is more responsive to the conditions the ISO observed in the MPA.[255]

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[248] *Id.* at 68–70, 73–74, 76–77; *see also* Ewing Testimony at 17.

[249] Alivand Testimony at 68–70.

[250] *See id.* at 76–77.

[251] *See id.* at 79–80.

[252] *Id.* at 64, 77, 79–80.

[253] *Id.* at 79.

[254] *Id.* at 79–80.

[255] *Id.*

C. Conduct-and-Impact Test Mitigation for Economic Withholding

Below are the details of the conduct-and-impact test that the Filing Parties propose to apply to Day-Ahead Ancillary Services Offers to screen for economic withholding.

1. Conduct Test Mechanics and Thresholds

The conduct test for economic withholding will set a threshold offer price that, if exceeded by any of the offer prices in a Day-Ahead Ancillary Services Offer, flags the offer as presumptively uncompetitive. As described above in Section V.F regarding offer formulation, competitive offers in the Day-Ahead Ancillary Services Market are expected to be cost-based. Consequently, the ISO has created a conduct test threshold formula that will generate thresholds for each resource for each offer-hour that reflects the resource's incremental costs of taking on a Day-Ahead Ancillary Services award. Because offers are made based on expected, rather than actual costs (which will only be known after the Operating Day), the conduct test threshold formula's components reflect expected costs.

The conduct test threshold will be calculated for each resource for each offer-hour as the sum of:

- the greater of $2/MWh and 200 percent of the Expected Close-Out Component; and
- 150 percent of the Avoidable Input Cost.

The Expected Close-Out Component represents the resource's expected close-out costs. The Avoidable Input Cost represents the resource's expected fuel or charging costs. A Day-Ahead Ancillary Services Offer violates the conduct test if any of the four offer prices (for any of the four Day-Ahead Ancillary Services) within the offer exceed this threshold.

a. *Expected Close-Out Component*

The Expected Close-Out Component is the expected close-out cost calculated for each offer-hour. The Expected Close-Out Component will be calculated by the ISO using the GMM and will be the same for every resource.[256] The GMM's calculation of the Expected Close-Out Component is the expected close-out charge for the hour, taking into account the distribution of potential Real-Time Hub Prices for that hour.[257] As explained in Section V.F.1 above, the expected close-out charge for any given hour should be the same for every resource because it is simply a function of the distribution of Real-Time Hub Prices and the strike price. In rare circumstances, the ISO will adjust the GMM's standard calculation of the expected close-out

[256] *Id.* at 82.

[257] *Id.*

using what it refers to as a "safety cap" formula.[258] The purpose of the "safety cap" formula is to ensure that the conduct test threshold derived from the Expected Close-Out Component provides a meaningful check on uncompetitive offer prices during tight conditions and during the unlikely circumstance where the GMM's standard calculation generates an unrealistic expected close-out value.[259]

Suppliers also will have the opportunity to submit different expected close-out costs to the IMM through the consultation process. Suppliers seeking to use their own expected close-out values will be expected to submit the models supporting those values to the IMM for review and validation, however.[260] The consultation process is discussed further below.

The ISO is setting the conduct test threshold to allow for offer prices that reflect twice, or 200 percent of, the Expected Close-Out Component. This range will allow for three elements that resources may build into the offer price: risk premiums; the errors and inaccuracies inherent in predicting close-out values using any model; and a supplier's reasonable expectation that Real-Time outcomes will differ from what is expected.[261] The first element, risk premiums, is the driving factor behind the 200 percent value. In the ISO's simulations of the proposed Day-Ahead Market, the ISO simulated competitive offers for Day-Ahead Ancillary Services suppliers, and such simulated offers included risk premiums that reflected suppliers' historical risk-return preferences in the Real-Time energy market.[262] As explained by Dr. Alivand, using this data, the ISO determined that this range above the Expected Close-Out Component would accommodate 97 percent of the risk-premium components of the simulated offers in the competitive case simulations of the MPA's 46 study days.[263] To cover a larger portion of risk premiums, the range above the Expected Close-Out Component would need to be raised to levels

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[258] *Id.* at 83.

[259] *Id.* at 83–90. As Dr. Alivand explains in his testimony, the GMM's standard calculation can, in rare circumstances, generate an expected close-out value that exceeds the expected Real-Time Hub Price, even when expected Real-Time Hub Prices are high and make such an expected close-out value unlikely. *See id.* at 84. To address this, the ISO developed an expected close-out calculation method that will provide an alternative value when (1) expected Real-Time Hub Prices exceed $100/MWh and (2) the alternative value is less than the GMM standard calculation value. *Id.* at 84–88. In the ISO's simulations of the proposed Day-Ahead Ancillary Services Market mitigation design, the conditions for using the "safety cap" formula-derived value never materialized, that is, the formula was never "triggered." *Id.* at 85–86. Consequently, the ISO anticipates the "safety cap" value will be needed only in rare circumstances but proposes the "safety cap" formula as a safeguard against a possible but unlikely risk of under-mitigation during tight conditions. *Id.*

[260] *Id.* at 118–19.

[261] *Id.* at 90.

[262] *Id.* at 90–91.

[263] *Id.* at 91. Dr. Alivand explains that the 200 percent range accommodated 99.9 percent of the risk-premium components of the simulated offers that cleared in the competitive case simulations. *Id.*

that would weaken protections against market power and could result in under-mitigation.[264] From this, the ISO determined that 200 percent accommodated a reasonable range of risk premiums, as well as modeling errors and reasonable variances in supplier expectations about Real-Time outcomes.[265]

Finally, the ISO's conduct test threshold formula incorporates a $2/MWh floor for the Expected Close-Out Component to ensure that the conduct test threshold allows for the inclusion of some meaningful risk premium when expected close-out values are low. As Dr. Alivand explains, if the GMM-determined expected close-out value is, for example, $0.02/MWh, the two-times multiplier results in a conduct test threshold of $0.04/MWh for a resource that has an Avoidable Input Cost of zero (discussed further in the next section).[266] This leaves only $0.02/MWh for other variables that the resource may reasonably consider when making a competitive offer, such as a risk premium or slight variation in the calculation of the expected close-out charge.[267] To address this concern, the ISO determined a floor for this element by considering the range of expected and actual close-outs when system conditions are unfavorable to successful exercises of market power (*i.e.*, when prices and expected close-outs are low).[268] The ISO determined from this data that a $2/MWh was sufficient to allow for a reasonable range of risk premiums when expected close-out values are very low without risking under-mitigation.[269]

b. *Avoidable Input Cost*

The Avoidable Input Cost element of the conduct threshold formula represents the avoidable natural gas or charging costs that are incremental to the Day-Ahead Ancillary Services Offer. As explained above in Section V.F.2, only those natural gas-fired and storage resources that make Day-Ahead fueling or charging decisions (respectively) as a result of the Day-Ahead Ancillary Services award will have incremental costs associated with these awards.[270] Reflecting this, the Avoidable Input Cost element will only be positive for those resource types, and only when the fueling or charging costs are expected to be incurred but for the Day-Ahead Ancillary Services award sought by making the offer.[271] Other resource technology types will not have

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[264] *Id.* at 92.

[265] *See id.* at 90–92.

[266] *Id.* at 92.

[267] *Id.*

[268] *Id.* at 93–94.

[269] *See id.* at 92–94.

[270] *Id.* at 95.

[271] *See id.* at 95–101.

such incremental costs, and their Avoidable Input Cost will be set to zero when calculating the conduct test threshold.

The ISO will calculate natural-gas resource and storage resource Avoidable Input Costs using methodologies that will ensure consistent treatment among those resources. For a natural-gas resource, the ISO will use a methodology that looks at (1) the direct cost of nominating gas prior to the Operating Day, (2) the expected loss (if any) from the intraday sales of natural gas not used in Real-Time to produce energy, and (3) the resource's expected net revenues of producing energy in Real-Time when nominating gas Day-Ahead compared to the expected net revenues of producing energy in Real-Time when nominating gas intraday.[272] As Dr. Alivand explains, because natural gas is the marginal resource on the system during most hours, the ISO devised a simplified formula for Avoidable Input Costs that considers all three factors by finding the cost of gas Day-Ahead and subtracting the expected Real-Time Hub Price.[273]

For storage resources, the ISO will use a calculation methodology that considers the direct cost of pumping or charging the storage resource (adjusted for the round-trip efficiency of the resource), the expected Real-Time energy revenue for the award-hour, and the expected value of any unused charge.[274] As Dr. Alivand explains, the ISO will calculate the direct cost of charging by looking at the three lowest expected Real-Time Hub Prices in the first eight hours of the Operating Day, adjusted by the resource's round-trip efficiency, and comparing those prices to the expected revenues in the award-hour and other potential discharge hours.[275] As with Avoidable Input Costs for natural-gas resources, if the cost of pumping or charging in those three hours is a cost the resource would have incurred completely independent of a Day-Ahead Ancillary Services award (*i.e.*, it expected to profit from charging during those hours and producing during the award-hour anyway), then the Avoidable Input Cost would be zero.[276]

The conduct test threshold will allow for offer prices that are 150 percent of the ISO-calculated Avoidable Input Cost. This 50 percent range above the Avoidable Input Cost will allow for resource-specific variations in fuel and charging costs that cannot be incorporated into standard formulas.[277] This range also accommodates potential errors that might occur from using these standard formulas.[278] The ISO concluded that 150 percent created an appropriate range by considering the incremental cost components of the simulated competitive offers (described above in Section VI.C.1.a) that cleared in the competitive case simulations of the MPA's 46

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[272] *See id.* at 95–98.

[273] *See id.*

[274] *Id.* at 99–101.

[275] *Id.*

[276] *Id.* at 100–01.

[277] *See id.* at 101.

[278] *Id.*

study days.[279] The 150 percent range accommodated more than 99.5 percent of the input cost components of the simulated competitive offers used in the MPA.[280]

2. Impact Test Thresholds and Mechanics

The impact test will set a threshold at which Day-Ahead Ancillary Services Offers flagged by the conduct test are considered to have raised Day-Ahead Market prices and impacted the competitiveness of the Day-Ahead Market. In establishing a threshold for the impact test, the ISO targeted a threshold level that would apply mitigation when an offer materially raises prices, thus reflecting a successful exercise of market power, and will avoid mitigating offers that may be high but do not impact the market. The proposed impact test threshold for each offer-hour will be 150 percent of the median difference between the following:

- the conduct test threshold prices for all Day-Ahead Ancillary Services Offers submitted for the offer-hour; and
- the Benchmark Levels for all Day-Ahead Ancillary Services Offers submitted for the offer-hour.

Benchmark Levels are simply the sum of the resource's Expected Close-Out Component and Avoidable Input Cost for the offer-hour, and they represent the ISO's estimated, competitive cost-based offer for the resource.[281] Benchmark Levels in the Day-Ahead Ancillary Services Market mitigation structure are analogous to the cost-based Reference Levels the ISO uses in its energy market mitigation.

To perform the impact test, the ISO will measure changes in Day-Ahead prices caused by Day-Ahead Ancillary Services Offers by conducting two runs of the Day-Ahead Market. The first run (referred to as the "offer run") will run the Day-Ahead Market using the Day-Ahead energy and ancillary services offers as submitted by the resources. The second run (referred to as the "mitigation run") will run the Day-Ahead Market by replacing all of the Day-Ahead Ancillary Services Offer prices that exceeded their respective conduct test thresholds in the offer-hour with the resources' Benchmark Levels. The ISO will look at the difference in Day-Ahead LMP, the FER Price, and the Day-Ahead Ancillary Services clearing prices between the two runs to measure the price impacts of the Day-Ahead Ancillary Services Offers that violate the conduct test in a single offer-hour.[282]

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[279] *Id.* at 102.

[280] *Id.*

[281] *Id.* at 105.

[282] *Id.* at 105–06. In his testimony, Dr. Alivand explains the use of a single mitigation run, including both the infeasibility and impracticality of conducting individual mitigation runs for every offer price that violates the conduct test in a given offer-hour. *See id.*

Any price increases observed in the offer-hour are then compared to the impact test threshold, which is determined for the offer-hour using the formula above. The ISO bases the threshold on the median difference between (1) all of the conduct test thresholds for offers submitted in the offer-hour and (2) all of the Benchmark Levels for offers submitted in the offer-hour. As Dr. Alivand explains, this measure reflects the range of prices that could exist if all of the Day-Ahead Ancillary Services Offer prices had stayed within the bounds of the conduct test thresholds.[283] Namely, it establishes the range of prices above the mitigation run that would have existed if suppliers had set their offer prices at or just below their conduct test thresholds.[284] The ISO uses the median difference for this measure, as opposed to mean difference, so that outlier values do not overly influence this base threshold measure.[285]

The ISO proposes to allow price increases that are 150 percent of the base threshold measure to avoid unnecessary mitigation of certain offers.[286] The 150 percent range accommodates a limitation of using a single mitigation run, which in some cases may result in mitigation of offer prices that, by themselves, would not violate the impact test.[287] Relying on its simulations of the proposed Day-Ahead Market, the ISO determined that 50 percent above the base threshold measure should be sufficient to correct for this limitation without under-mitigation.[288]

3. Mitigation

If an increase in any Day-Ahead price exceeds the impact test threshold during the offer-hour, then the Day-Ahead Ancillary Services Offers that had offer prices above their conduct test thresholds are mitigated. Mitigation of the offer means that the offer prices within the Day-Ahead Ancillary Services Offer that violated the conduct test are set to the resource's Benchmark Level for that offer-hour. Offer prices that remain within the conduct test threshold are still submitted as offered, which is necessary to avoid upward mitigation.[289] For example, if only the DA TMSR offer price in a Day-Ahead Ancillary Services Offer violated the conduct test threshold and the DA TMNSR, DA TMOR, and DA EIR offer prices did not, then only the DA TMSR offer price is mitigated to the Benchmark Level. Because the mitigation run used for the impact test already sets conduct-test-violating offer prices to the relevant resources' Benchmark

[283] *See id.* at 107–09 (also providing simplified example of impact test threshold calculation).

[284] *Id.*

[285] *Id.* at 108.

[286] *See id.* at 109–11.

[287] *See id.*

[288] *See id.* at 110–11.

[289] *Id.* at 112–13.

Levels, the mitigation run thereby determines the outcomes of the Day-Ahead Market in hours when mitigation applies. Offers are mitigated only for the offer-hour.[290]

Importantly, market power mitigation in this circumstance relies on setting offer prices at Benchmark Levels, which are offers that do not incorporate risk premiums. As explained above, the conduct test threshold formula's allowance for twice the Expected Close-Out Component is the aspect of the proposed conduct-and-impact test threshold that allows suppliers to build risk premiums into their offer prices. The reason for using Benchmark Levels for mitigation, as opposed to conduct test thresholds, is the deterrence aspect of this method.[291] If the ISO were to mitigate offer prices down to conduct test thresholds (which incorporate risk premiums), suppliers would have little disincentive against submitting uncompetitively high offer prices to test whether their high offer prices trigger a market impact. Suppliers would know that the worst outcome of this strategy is mitigation down to the more lenient conduct test threshold.[292]

Suppliers can avoid violating the conduct test, and potential mitigation down to their resource's Benchmark Levels, by heeding conduct test thresholds or consulting with the IMM regarding their expected costs. If a conduct test threshold truly does not represent the supplier's incremental costs of a Day-Ahead Ancillary Services award, the supplier should be taking advantage of the consultation or Fuel Price Adjustment processes (described further below), rather than submitting offer prices that violate the conduct test threshold.

4. Validation of the Proposed Conduct-and-Impact Test

The ISO conducted simulations that included application of the proposed conduct-and-impact test to determine if the conduct-and-impact test would strike the right balance between over- and under-mitigation. In its simulations, the ISO found that the conduct test had a false positive rate (*i.e.*, flagged simulated competitive offers as violating the test) of only 0.1 percent.[293] The ISO also found in its simulations that the proposed conduct-and-impact test dramatically reduced the price impacts seen in the MPA's simulated withholding scenarios.[294] Dr. Alivand elaborates further on the validation process and the data from these simulations.[295]

D. Consultation Process and Fuel Price Adjustments

The Filing Parties propose to adjust the existing consultation process and Fuel Price Adjustment process to incorporate Day-Ahead Ancillary Services Offers into both processes.

[290] *Id.* at 113.

[291] *Id.* at 111–12.

[292] *Id.* at 112.

[293] *Id.* at 103.

[294] *See id.* at 114–16.

[295] *See id.*

For the consultation process set forth in Sections III.A.3 and III.A.3.1 of Appendix A to Market Rule 1, the Filing Parties propose tariff changes that will allow suppliers to consult with the IMM prior to the submission of Day-Ahead Ancillary Services Offers regarding components of the conduct test thresholds and Benchmark Levels that will apply to the supplier's resources. As noted above, suppliers will have the opportunity to present alternative expected close-out calculations to the IMM, though they will need to do so such that the IMM can review and assess the validity of any model the supplier is using to calculate alternative expected close-out values.[296] This assessment necessarily requires that the supplier present the model well in advance of the Day-Ahead Market.[297] Similarly, suppliers will be able to consult with the IMM regarding fuel, charging, or other incremental costs that the supplier believes are not properly accommodated by the 50 percent range above the ISO-determined Avoidable Input Cost value allowed by the conduct test threshold formula. The IMM will be empowered to adjust the components of Benchmark Levels or simply deem the supplier's offer prices as not violating the conduct test. However, the supplier must submit verifiable and documented information supporting its consultation requests to enable the IMM to adjust Benchmark Level components or accept an offer price.

Regarding the Fuel Price Adjustment process in Section III.A.3.4 of Appendix A, this process will remain as it does today, except that fuel prices submitted for use in setting mitigation threshold levels through this process will be used both in the energy market and also to adjust Avoidable Input Costs for natural gas resources. A fuel price submitted through this process will automatically be used in both energy market and Day-Ahead Ancillary Services Market mitigation.[298] For a supplier that believes a fuel price should apply only to its Day-Ahead Ancillary Services Offer, that supplier would need to present the fuel price to the IMM through the consultation process, rather than the Fuel Price Adjustment process, with enough time for the IMM to review the fuel price prior to the close of the Day-Ahead Market.

E. Cost-Recovery Petitions

The Filing Parties also are proposing to adapt the existing mitigation-related cost-recovery rules in Section III.A.15.2 of Appendix A to incorporate cost recovery related to Day-Ahead Ancillary Services Offer mitigation. Section III.A.15.2 currently sets forth a Section 205 filing right for a Market Participant that believes it is unable to recover costs that it reflected in its energy offer due to having its offer mitigated. The Filing Parties propose to incorporate into this process petitions to recover costs related to mitigated Day-Ahead Ancillary Services Offers. Specifically, the proposed adjustments to Section III.A.15.2 will allow a supplier to recover actual close-out costs or other incremental costs (referred to as "input costs") that it suffered due to mitigation of its Day-Ahead Ancillary Services Offer. In seeking recovery of these costs,

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[296] *Id.* at 118–19.

[297] *See id.*

[298] *Id.* at 119–21 (discussing consultation regarding Avoidable Input Costs and Fuel Price Adjustment).

however, the supplier needs to explain why its offer should not have been mitigated and provide documentation and information sufficient to show that its original offer was supported by the supplier's rational expectation of costs at the time the offer was made.[299]

The Filing Parties also propose to allow a supplier to seek opportunity costs that it experienced within the Day-Ahead Market as a result of Day-Ahead Ancillary Services Offer mitigation. The simplest example of when this type of opportunity cost arises is when mitigation of a Day-Ahead Ancillary Services Offer results in a resource clearing for a Day-Ahead Ancillary Services product in lieu of receiving a Day-Ahead energy award for those same MWh.[300] This would occur if an extra-marginal Day-Ahead Ancillary Services offer price is mitigated to a Benchmark Level that is infra-marginal, and as a result of the Day-Ahead MCE jointly optimizing awards across all Day-Ahead products, then clears for that Day-Ahead Ancillary Services product rather than Day-Ahead energy.[301] If receiving an award for Day-Ahead energy would have been more profitable for the resource but for the application of mitigation, then it incurs an opportunity cost that the ISO's proposed changes to Section III.A.15.2 would allow the resource to recover, provided that the resource demonstrates that its original offer price was well-supported by costs that the supplier anticipated at the time the offer was made (thus justifying the recovery of those additional costs despite being mitigated).[302] Dr. Alivand provides a detailed example of what these opportunity costs are and how they are calculated.[303]

Recovery of opportunity costs extends only to such opportunity costs that occur within the Day-Ahead Market on the same day as the mitigation—meaning, across Day-Ahead Market products—and does not extend to claims that the resource also experienced opportunity costs in the Real-Time energy market, some other ISO-administered market, or some market entirely outside of the ISO's wholesale markets. As Dr. Alivand explains, cost-recovery calculations also would not include or recognize netting of Real-Time market profits because of the potential distortions that might result in the Real-Time energy market.[304] Namely, a supplier that believes it has grounds for cost recovery coming out of the Day-Ahead Market might have the incentive to avoid clearing for energy or to inflate its Real-Time energy offer to show smaller profits in Real-Time in order to maximize its cost recovery.[305] Overall, the consideration of costs, including opportunity costs, that result from Day-Ahead Ancillary Services Offer mitigation is restricted to losses experienced within that day's Day-Ahead Market only.

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[299] *Id.* at 121–27 (discussing adjustment to cost-recovery rules).

[300] *See id.* at 123–26.

[301] *See id.*

[302] *See id.*

[303] *Id.*

[304] *Id.* at 126–27.

[305] *Id.*

F. Conduct-and-Impact Test Thresholds and Mitigation for Physical Withholding

Finally, the Filing Parties propose conduct-and-impact thresholds to address physical withholding in the Day-Ahead Ancillary Services Market. The proposed conduct-and-impact thresholds will function very similarly to the current physical withholding conduct-and-impact thresholds that apply in the ISO's energy markets. Under current rules, the Tariff's physical withholding conduct thresholds in Section III.A.4.2 of Appendix A are intended to serve as a guide to the IMM to identify instances of physical withholding in the energy markets. If the IMM suspects physical withholding has occurred, it does the following pursuant to Section III.A.4.3: (1) consults with the supplier identified that engaged in such behavior and (2) determines a price impact according to impact test thresholds used for evaluating economic withholding, if necessary to do so after consultation. If the IMM determines that impactful physical withholding has occurred, it will refer the supplier to the Commission's Office of Enforcement.

The ISO will apply this same physical withholding mitigation framework to Day-Ahead Ancillary Services Offers, albeit with different conduct-and-impact thresholds. For the conduct threshold, the ISO proposes a threshold of withholding that exceeds the greater of 20 percent or 100 MW of the total Day-Ahead Ancillary Services capability of a Market Participant's portfolio of resources. The threshold effectively has a floor of 100 MW before suspected withholding is identified because, in the MPA simulations, withholding 100 MW had no meaningful impact on Day-Ahead prices.[306] The 100 MW floor also will allow for varying measurements of resource ancillary service capabilities across seasons and variations in ancillary service capability across the dispatch range of a resource that cannot be fully reflected in the Day-Ahead MCE.[307] The ISO also is employing a 20 percent threshold—which allows up to 20 percent of a portfolio's ancillary services capability to remain unoffered—because such withholding showed, at most, only inconsequential impacts on Day-Ahead prices in the MPA simulations.[308] For the impact threshold, the IMM will use, when necessary, the same impact test threshold proposed for economic withholding mitigation in the Day-Ahead Ancillary Services Market, described above in Section VI.C.2.

Importantly, the conduct-and-impact thresholds established for the Day-Ahead Ancillary Services Market are intended to guide the IMM's inquiry into suspected incidences of physical withholding in the Day-Ahead Ancillary Services Market. As with the energy markets, a violation of these thresholds does not result in an automatic determination by the IMM that the

[306] *Id.* at 129–31.

[307] *Id.*

[308] *Id.*

supplier has engaged in physical withholding.[309] Rather, it becomes one among other factors that the IMM uses to conclude whether physical withholding has occurred.[310]

Moreover, the ISO strongly encourages suppliers to take advantage of the consultation process in advance of the close of the Day-Ahead Market to assist the IMM in understanding a supplier's rationale for withholding ancillary services capability in amounts that would exceed the physical withholding conduct threshold. Importantly, the proposed revision to Section III.A.4.1(b) of Appendix A will clarify that physical withholding in the Day-Ahead Ancillary Services context includes the refusal to offer ancillary services capabilities "when it would be in the economic interest" of the supplier "absent market power."[311] Consultation with the IMM ahead of the close of the Day-Ahead Market to present a valid and credible rationale for abstaining from making an offer (*i.e.*, explaining why making an offer would be uneconomic or infeasible) can alleviate supplier concerns about an *ex post* withholding inquiry.

VII. ANTICIPATED COSTS OF THE PROPOSED CHANGES TO THE DAY-AHEAD MARKET

The ISO conducted an assessment of the extent to which the joint Day-Ahead Market is likely to impact suppliers' revenues, and conversely, costs to consumers (referred to herein after as the "Impact Assessment"). The Impact Assessment was conducted by running market simulations that compare revenue and cost outcomes under current market rules and the outcomes likely to occur under the proposed rule changes presented in this filing. The ISO simulated market outcomes under current market rules using input data from 2019 through 2021 and compared them to simulated market outcomes with the proposed DASI changes in effect, also using input data from 2019 through 2021.[312] The ISO chose this period because the period was recent enough to represent New England's current resource fleet and also provided a wide variation in energy demand, natural gas prices, and Day-Ahead LMPs.[313]

For the DASI simulation, the ISO also included a simulated market response as part of its assessment. As explained above and in Mr. Ewing's testimony, the ISO expects that, over time,

[309] *Id.* at 133.

[310] *See* Internal Market Monitor Memorandum to NEPOOL Markets Committee, *Current Market Rules on Physical Withholding*, at 4–6 (Nov. 30, 2022) (explaining circumstances IMM considers when reviewing potential incidences of physical withholding, and encouraging consultation), *available at* https://www.iso-ne.com/static-assets/documents/2022/11/a06_mc_2022_12_06_08_imm_memo.pdf.

[311] Marked Tariff, Section III.A.4.1(b).

[312] Ewing Testimony at 80–83. Mr. Ewing explains why the ISO used simulated market outcomes of the years 2019 through 2021 using current market rules, as opposed to observed historical outcomes, to compare to simulated market outcomes of the years 2019 through 2021 using the proposed DASI rules. Mr. Ewing also describes the details of how the ISO-simulated Day-Ahead Ancillary Services Offers for the DASI simulation and the ISO's testing of the simulation platform. *Id.* at 80–85.

[313] *Id.* at 81.

load will respond to any potential decrease in Day-Ahead LMPs resulting from DASI by submitting more priced demand bids into the Day-Ahead Energy Market.[314] This shift in bidding behavior will result in the proposed Day-Ahead Market clearing more energy than it does under current market rules and, thus, a convergence of Day-Ahead LMPs with expected Real-Time LMPs.[315] To reflect this expected change in bidding behavior, the ISO added additional energy demand bids into the Impact Assessment's simulation of the proposed Day-Ahead Market.[316]

The following results of the Impact Assessment present the simulated change in energy and ancillary services revenues with and without DASI for the years from 2019 to 2021, and reflect the addition of demand bids to simulate the expected market response. Overall, the simulation shows an average annual increase in energy and ancillary services revenues of $139.9 million, which represents an approximate average annual increase in wholesale market costs of 1.4 percent.[317] This $139.9 million increase is composed of $273.3 million in increased Day-Ahead energy and ancillary services credits to suppliers (which are charges to load), net of $133.4 million in close-out charges to suppliers (which are credited back to load) and expected decreased Real-Time energy costs for load.[318]

Overall, procurement of the new Day-Ahead Ancillary Services products (*i.e.*, DA TMSR, DA TMNSR, DA TMOR, and DA EIR) resulted in an annual net increase of revenues to suppliers and costs to load of $21.5 million.[319] The $21.5 million represents a total $90.3 million in credits to suppliers minus $68.8 million in close-out charges credited back to consumers.[320]

Energy costs showed a gross increase in Day-Ahead energy credits to suppliers of $183 million, with $125.3 million attributable to FER credits to suppliers and $57.7 million attributable to Day-Ahead LMP credits to suppliers.[321] The increase in Day-Ahead LMP credits was the result of the increase in cleared Day-Ahead energy quantities, rather than an increase in the Day-Ahead LMPs.[322] In fact, the Impact Assessment showed an estimated annual increase of 2,000 GWh of Day-Ahead cleared energy under the proposed rules, which represents an approximate 1.7 percent increase above the amount cleared under current rules.[323] The Impact

[314] *Id.* at 56.

[315] *Id.*

[316] *Id.* at 84.

[317] *Id.* at 85.

[318] *Id.* at 85–86.

[319] *Id.* at 86–87.

[320] *Id.*

[321] *Id.* at 86–89.

[322] *Id.* at 88.

[323] *Id.*

Assessment only showed an increase in Day-Ahead Hub Prices that was on average $0.01/MWh or 0.58 percent higher than Day-Ahead Hub Prices observed in the simulation under current market rules.[324]

The gross increase in Day-Ahead energy credits to suppliers of $183 million was offset in part by $64.6 million in expected consumer savings that resulted from decreased procurement of Real-Time energy at Real-Time LMPs.[325] Thus, the net increase in energy costs was only $118.4 million.[326] This is consistent with the expectation that load will increase its Day-Ahead participation, which will result in a decreased need for load to purchase energy in Real-Time at Real-Time prices.

The Impact Assessment also provided insight into representative prices that may be observed in the proposed Day-Ahead Market. As mentioned above, the simulation showed an average penny increase in the Day-Ahead Hub Price, suggesting effectively no change in Day-Ahead LMPs.[327] The FER Price was zero in 69 percent of hours, resulting in a low mean FER Price of $0.95/MWh.[328] DA TMSR prices were on average $6.14/MWh, with a 99th percentile price of $29.80/MWh.[329] DA TMNSR and DA TMOR prices were substantially similar, with their average prices being $3.58/MWh and $3.56/MWh, respectively.[330] The 99th percentile prices for DA TMNSR and DA TMOR in the simulation were $15.88/MWh for both.[331]

Due to interest from stakeholders, the ISO examined what the impact on total energy and ancillary services revenues/costs would be if the ISO set the strike price at the expected Real-Time Hub Price without the $10/MWh base strike adder.[332] The result showed an average annual increase in energy and ancillary services costs without the base strike adder of $159.4

[324] *Id.* at 94.

[325] *Id.* at 89–91.

[326] *See id.* at 86 (sum of cells B1 + B4, minus B6, from Table 4).

[327] *Id.* at 94.

[328] *Id.* Mr. Ewing explains how the FER price was zero in 69 percent of hours when the energy gap calculated for those same years, 2019 to 2021, under current market rules had been approximately 50 percent of hours. *Id.* at 92–94. In short, the simulated increase of demand participation in the Day-Ahead Market is likely the main reason for this result. *See id.*

[329] *Id.* at 95.

[330] *Id.*

[331] *Id.*

[332] *Id.* at 96.

million, which is $19.5 million, or 12 percent, higher than the $139.9 million under the proposed design.[333]

The ISO also studied other impacts related to the DASI proposal. Taking into account the elimination of the FRM and an expected decrease in NCPC payments, there was an additional savings of approximately $35.5 per year on average.[334] With these additional savings, the Impact Assessment showed an average annual increase of $104.4 million as a result of DASI, which is only an average annual increase of 1.1 percent in wholesale market costs to consumers.[335]

The ISO was unable to study the proposed Day-Ahead Market's impacts on Forward Capacity Market revenues and costs to consumers due to the number of challenging assumptions that could not be reliably supported concerning potential retirements, a shifting supply stack, and future possible adjustments to Net CONE.[336] Further, the ISO's current Resource Capacity Accreditation project has the potential to significantly change how resources are compensated through the Forward Capacity Market.[337] Thus, attempts to estimate capacity market impacts at this time would be of limited utility, although the ISO does anticipate that, in the long run, capacity market payments would generally decrease as energy and ancillary services revenues increase as a result of DASI.[338]

VIII. REVIEW OF THE PROPOSED DAY-AHEAD MARKET'S PERFORMANCE

Once the proposed Day-Ahead Market is implemented, the ISO intends to review the new Day-Ahead Market's performance after its implementation, as it does with all of its new market designs. If it appears that the market is not working as intended or requires adjustments, the ISO would investigate the necessity of any design changes, propose such design changes to stakeholders, and seek Commission approval for any such adjustment. For example, if the region's resource mix or other market conditions change in such a way that the base strike adder needs revision, the ISO will investigate the possibility of revision and bring forward a proposal

[333] *Id.* at 96–97.

[334] *Id.* at 97–101 (average change in column 1, minus average total in column 4, in Table 10).

[335] *Id.* at 100–01. As Mr. Ewing notes, net FRM credits have increased in recent years, suggesting that elimination of the FRM might result in even greater savings if the FRM were to continue its recent trend. *Id.* at 98.

[336] *Id.* at 101.

[337] *Id.* at 101–02.

[338] *Id.* As Mr. Ewing explains, the Forward Capacity Market's function in addressing the "missing money" problem for resources is the basis for the general assumption that, over the long run, Forward Capacity Market payments would decrease as energy and ancillary services revenues increase. *Id.* at 102.

to stakeholders and the Commission.[339] This type of review of a design element in a major market is not novel, however, as the ISO regularly evaluates the performance of its markets.

As indicated above, the ISO will not just review the performance of the new Day-Ahead Market but also the performance of the GMM used to calculate the expected Real-Time Hub Prices used in determining the strike price and the Expected Close-Out Components of a resource's Benchmark Levels and conduct test thresholds. The ISO will periodically update the model as needed, and when making such updates, provide notice to Market Participants and stakeholders so that they are aware of such updates.

Further, the Filing Parties propose a revision to Appendix A of Market Rule 1 to add a new ad hoc reporting requirement for the IMM regarding the overall competitiveness and performance of the New England markets, including major market designs. This change is responsive to stakeholder requests for such a review. The new language will require the IMM 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.

IX. EXPLANATION OF THE PROPOSED TARIFF CHANGES

The following is a summary of the proposed revisions to Sections I.2.2, Market Rule 1, and Appendix A to Market Rule 1 of the Tariff that will create the proposed Day-Ahead Ancillary Services Market and joint Day-Ahead Market.

A. Section I.2.2 Revisions

The Filing Parties propose to add definitions to Section I.2.2 of the Tariff to effect incorporation of the Day-Ahead Ancillary Services Market into the joint Day-Ahead Market, as described above. The following definitions concern the new market and its products: Day-Ahead Market; Day-Ahead Ancillary Services; Day-Ahead Ancillary Services Market; Day-Ahead Ancillary Services Offer; Day-Ahead Ancillary Services Strike Price; Day-Ahead Energy Imbalance Reserve; Day-Ahead Flexible Response Services; Day-Ahead Ten-Minute Spinning Reserve; Day-Ahead Ten-Minute Non-Spinning Reserve; Day-Ahead Thirty-Minute Operating Reserve; and Forecast Energy Requirement Price. The following definitions name the new reserve requirements, also known as demand quantities, that will be incorporated into the Day-Ahead Market: Day-Ahead Flexible Response Services Demand Quantities; Day-Ahead Ten-Minute Spinning Reserve Demand Quantity; Day-Ahead Total Ten-Minute Reserve Demand Quantity; Day-Ahead Minimum Total Reserve Demand Quantity; Day-Ahead Total Reserve Demand Quantity; and Forecast Energy Requirement Demand Quantity. The following definitions name obligations related to Day-Ahead Ancillary Services awards and are used primarily in the Tariff's settlement rules: Day-Ahead Energy Imbalance Reserve Obligation;

[339] *See* Alivand Testimony at 28–29.

Day-Ahead Ten-Minute Spinning Reserve Obligation; Day-Ahead Ten-Minute Non-Spinning Reserve Obligation; and Day-Ahead Thirty-Minute Operating Reserve Obligation.

The new definition Forecast Energy Requirement Penalty Factor describes the penalty factor used with regard to the FER. The new definition Maximum Daily Award Limit names the optional offer parameter available to suppliers making Day-Ahead Ancillary Services Offers. The following definitions name the elements of the proposed market power mitigation structure that will be used to screen and, if necessary, mitigate Day-Ahead Ancillary Services Offers: Day-Ahead Ancillary Services Avoidable Input Cost; Day-Ahead Ancillary Services Benchmark Level; and Day-Ahead Ancillary Services Expected Close-Out Component.

The Filing Parties also propose revisions to existing definitions in Section I.2.2 of the Tariff. The proposed revision to the Day-Ahead Energy Market definition to include a reference to Section III.1.8 of the Tariff (the section that will set forth the Day-Ahead Ancillary Services Market) reflects the joint optimization of both markets. The proposed revision to the Day-Ahead Prices definition is an update such that the term will refer to Day-Ahead LMPs, the FER Price, and the Day-Ahead Ancillary Services clearing prices. The proposed revision to the Forward Reserve Procurement Period definition is intended to specify that the final period will be a shortened period running only until February 28, 2025. The proposed revision to the Lead Market Participant definition is to specify which party is authorized to submit Day-Ahead Ancillary Services Offers. The proposed revision to the Reserve Constraint Penalty Factor definition is intended to ensure RCPF applicability in the Day-Ahead Market as proposed above. The proposed revision to the Reference Level definition is to correct an incorrect cross-reference to Appendix A that is unrelated to the DASI proposal changes.

The Filing Parties also propose additional revisions to Section I.2.2 definitions that will update cross-references to sections of Market Rule 1 that will be revised as part of this proposal. Those are not detailed here.

B. Market Rule 1 Revisions

1. Proposed Section III.1.8

The Filing Parties propose the addition of Sections III.1.8.1, III.1.8.2, III.1.8.3, and III.1.8.4 to set forth the Day-Ahead Ancillary Services Market consistent with the design described above. Section III.1.8.1 sets forth the format and requirements for submitting Day-Ahead Ancillary Services Offers. The only aspect of the proposed Section III.1.8.1 language not discussed above is the stated requirements that offer prices "not exceed the Forecast Energy Requirement Penalty Factor" and that the offer quantity "not exceed the Economic Maximum Limit, . . . Maximum Reduction, . . . , or the Maximum Consumption Limit" associated with the resource's respective energy offer. These two requirements ensure that resources are not submitting high offer prices that cannot clear due to the FER Penalty Factor or offering ancillary services supply amounts that are inconsistent with the resource capabilities represented in a corresponding energy offer for the same time period.

Proposed Section III.1.8.2 is intended to effect the strike price design, including the strike price formula, described at length above. Section III.1.8.2 is explicit that the ISO "shall periodically review and assess the efficacy of the forecasting algorithm" used in determining the strike price (*i.e.*, the GMM) and that it "shall notify stakeholders of any potential revisions to the forecasting algorithm prior to implementing such revisions." Section III.1.8.2 also sets forth a backstop provision that allows the ISO to use "the best forecast available" if, due to unforeseen circumstances, the ISO is unable to use its GMM to determine strike prices. In such an event, Section III.1.8.2 specifies that the ISO "shall disclose the use of such substitute forecast to Market Participants as soon as practicable."

Proposed Section III.1.8.3 sets forth the calculation of the Day-Ahead Flexible Response Services Demand Quantities as "equal to" the corresponding Real-Time Operating Reserve requirements "projected Day-Ahead," that is, the anticipated reserve requirements for each hour of the Operating Day. Proposed Section III.1.8.4 sets forth the calculation of the FER Demand Quantity, which for each hour of the Operating Day "shall be equal to the ISO forecast for the total load in the New England Control Area produced pursuant to Section III.1.10.1A(h) of [] Market Rule 1." In short, the FER Demand Quantity shall equal the load forecast for the hour.

2. <u>Proposed Revisions Related to Day-Ahead Scheduling, Pricing, and Optimization</u>

The Filing Parties propose certain revisions to Section III.1 that are necessary to incorporate Day-Ahead Ancillary Services and the FER into the Day-Ahead Market, and that also better articulate the market clearing process that occurs in the Day-Ahead Market. The Filing Parties propose significant revisions to Section III.1.10.8(a) that clarify how the ISO's Day-Ahead MCE will use the various offers, bids, and demand quantities to determine a Day-Ahead schedule that is the result of joint optimization across all Day-Ahead products. The purpose of the Section III.1.10.8(a) revisions is to have one clear description in the Tariff of joint optimization-based market clearing in the Day-Ahead Market that will serve as a cross-reference for other Tariff provisions that discuss the Day-Ahead market clearing process.

Specifically, the Filing Parties propose to revise the first paragraph of Section III.1.10.8(a) to state, "In scheduling the Day-Ahead Market, the ISO shall use its best efforts to determine the security-constrained economic commitment and dispatch that jointly optimizes" the offers, demand bids, and demand quantities in the Day-Ahead Market, both for energy and ancillary services. The second paragraph of Section III.1.10.8(a) is revised to clarify that the market clearing process takes into account the region's ancillary services requirements, generally (not just in Real-Time) and the operational capabilities of each resource, as represented in the resource's Offer Data or energy offer and, if applicable to the situation, as audited by the ISO. The ISO eliminated in this second paragraph a reference to the determination of Day-Ahead Prices, as the reference is duplicative of pricing provisions addressed in Section III.2 of Market Rule 1. Finally, the Filing Parties propose to add a third paragraph to Section III.1.10.8(a) that incorporates the eligibility requirements for supplying Day-Ahead Ancillary Services products, which are described in detail in Section V.D above.

The Filing Parties also propose revisions to Section III.1.10.8(c) to clarify the process by which the ISO will meet unmet reliability requirements that are identified following the posting of the results of the Day-Ahead Market. The proposed revisions to Section III.1.10.8(d) are intended to update the payment provision to incorporate Day-Ahead Ancillary Services payments and clarify that the Day-Ahead Market now includes multiple Day-Ahead clearing prices.

Proposed revisions to Sections III.2.1 and III.2.2 connect the scheduling provision of Section III.1.10.8(a) to generating clearing prices for the Day-Ahead Market, and the revisions to Section III.2.2 also now note the role that the RCPFs and FER Penalty Factor will play in generating Day-Ahead Prices. Proposed revisions to Section III.2.6, which will be relabeled Section III.2.6.1, seek to eliminate language that would effectively repeat the scheduling process language of Section III.1.10.8(a), specifying instead that prices will "be determined on the basis of the Day-Ahead Market security-constrained economic commitment and dispatch process described in Section III.1.10.8(a)." Further edits to proposed Section III.2.6.1's provisions regarding the calculation of Day-Ahead energy prices are intended to clarify the existing process and recognize the joint optimization.

Section III.2.6 will be split into Sections III.2.6.1 and III.2.6.2. Section III.2.6.1 will house the current Section III.2.6 language, with proposed revisions as just described. Section III.2.6.2 is an entirely new section that will address the pricing of the new Day-Ahead Ancillary Services products and the FER. Section III.2.6.2(a) sets forth the marginal pricing (including shadow pricing) logic that will generate the Day-Ahead Flexible Response Services clearing prices, as well as scarcity conditions under which such prices will be determined based on the RCPFs. Section III.2.6.2(b) sets forth the marginal pricing logic that will generate the FER Price and the scarcity conditions under which the FER Price will be determined based on the FER Penalty Factor. Sections III.2.6.2(c) and III.2.6.2(d) set forth the RCPFs applicable in the Day-Ahead Market and the FER Penalty Factor.

3. <u>Proposed Revisions to Settlement Rules</u>

The Filing Parties propose revisions to Section III.3.2.1 to incorporate the Day-Ahead Ancillary Services and FER settlement and cost allocation rules into the Tariff. Current Section III.3.2.1(a) is now being relabeled as Section III.3.2.1(a)(1), and new Section III.3.2.1(a)(2) defines the obligations associated with taking on a Day-Ahead Ancillary Services award for the purpose of the settlement rules. Proposed new Sections III.3.2.1(q)(1) and III.3.2.1(q)(2) set forth the calculation of the credits and close-out charges associated with taking on a Day-Ahead Ancillary Services obligation. Section III.3.2.1(q)(3) sets forth the cost allocation of Day-Ahead Flexible Response Services costs to load, in accordance with the cost allocation described in Section V.H, as well as the credits back to consumers of any close-out charges collected from suppliers.

Section III.3.2.1(q)(4)(i) sets forth the calculation of FER credits to Generator Assets and DRRs with Day-Ahead energy awards. Section III.3.2.1(q)(4)(ii) sets forth the calculation of FER credits to Day-Ahead cleared imports, including the rule described above that limits FER credits to the amount of MWh offered in a corresponding Real-Time Energy Market transaction. Section III.3.2.1(q)(4)(iii) sets forth the cost allocation to load for FER credits and DA EIR credits. Finally, Section III.3.2.1(q)(4)(iv) sets forth the credits back to consumers for any close-out charges collected from DA EIR suppliers.

4. Proposed Revisions to Section III.9

The Filing Parties propose revisions to Section III.9 to effect the elimination of the FRM. The proposed revisions to Section III.9.1 set forth the timing of the final Forward Reserve Auction and the time period for the final Forward Reserve Procurement Period. The proposed revisions to Section III.9.5.3.1, substituting the references to the Forward Reserve Procurement Period with references to "Summer Capability Period or Winter Capability Period," are necessary to ensure the CLAIM10 and CLAIM30 calculation rules operate properly once the FRM is eliminated and no further Forward Reserve Procurement Periods exist. Similarly, the proposed revision to Section III.9.5.3.2(b) that substitutes a reference to the Forward Reserve Delivery Period with "between 0800 and 2200 on a non-NERC-holiday weekday" ensures that a time period for audits is specified even after elimination of the Forward Reserve Market.

5. Other Proposed Revisions to Market Rule 1

The Filing Parties propose other revisions to Sections III.1 and III.2 necessary to create the proposed joint Day-Ahead Market. The Filing Parties propose a slight revision to Section III.1.5.2(a) to eliminate the reference to "real-time," to clarify that ISO-initiated parameter auditing provisions apply equally with regard to Day-Ahead and Real-Time ancillary services. The proposed revision to Section III.1.7.6 is only to clarify that Section III.1.10.8(a) describes the Day-Ahead Market clearing process. The proposed addition of Section III.1.7.9A is to create a Day-Ahead Ancillary Services pricing provision analogous to the existing Real-Time reserve pricing provision in Section III.1.7.9. The proposed revisions to Sections III.1.10.1, III.1.10.1A, and III.1.10.2 are necessary adjustments to acknowledge the entire Day-Ahead Market, including the new Day-Ahead Ancillary Services Market. New Section III.1.10.1A(l) creates an offer provision for Day-Ahead Ancillary Services Offers analogous to the energy market offer and bid provisions throughout Section III.1.10.1.1A.

C. Appendix A Revisions

1. Proposed Section III.A.2 Revisions

Certain provisions regarding the IMM's general functions and responsibilities require incorporation of Day-Ahead Ancillary Services Market references. The proposed revisions to Sections III.A.2.3(j)(i) and III.A.2.3(m) incorporate monitoring of the Day-Ahead Ancillary Services Market for economic withholding and physical withholding into the IMM's general responsibilities. The proposed revision to Section III.A.2.3(l) incorporates the Day-Ahead Ancillary Services Market's mitigation measures into the IMM's role in proposing mitigation rule changes, when appropriate, to the ISO and to Market Participants. The proposed revisions to Sections III.A.2.4.2 and III.A.2.4.3 recognize that mitigation is applicable to Day-Ahead

Ancillary Services Offers. Finally, proposed Sections III.A.2.4.6 and III.A.2.4.7 are currently Sections III.A.5.9 and III.A.5.10, which have been relocated and revised such that they apply to both Supply Offers and Day-Ahead Ancillary Services Offers, and the Day-Ahead Market as a whole.[340]

2. Proposed Section III.A.8

The Filing Parties propose new Section III.A.8, which will set forth the conduct-and-impact test for economic withholding in the Day-Ahead Ancillary Services Market. Section III.A.8.1 sets forth the conduct-and-impact test threshold formulas as described above in Section VI.C, as well as the mitigation consequence of failing both tests (also consistent with what is described above). Section III.A.8.2 defines the Benchmark Levels used in the mitigation run. Section III.A.8.2.1 sets forth the Expected Close-Out Component calculation methodology, with subparagraph (a) expressing the GMM-determined expected close-out value[341] and subparagraph (b) expressing the "safety cap" formula.[342]

Section III.A.8.2.2(a) sets forth the methodology for calculating the Avoidable Input Cost for natural gas-fired resources (including dual-fuel resources), consistent with the methodology described in Section VI.C.1.b and Dr. Alivand's testimony. Similarly, Section III.A.8.2.2(b) sets forth the methodology for calculating the Avoidable Input Cost for storage resources, consistent with the methodology described in Section VI.C.1.b above and Dr. Alivand's testimony. Section III.A.8.2.2(c) and (d) set the Avoidable Input Cost to zero for all other resource technology-types and clarifies that Avoidable Input Costs are never negative. Section III.A.8.2.3 clarifies that the IMM may take into account information provided through consultation and that documentation and other criteria required for participant-supplied cost information for energy offers is also required for cost information submitted with reference to Day-Ahead Ancillary Services Offers.

Sections III.A.8.3 and III.A.8.4 specify the offer and mitigation runs that will be used to determine price impacts for impact test purposes and which prices will be compared. Although not expressly provided in the language of Section III.A.8.3, impacts to the FER Price will be measured because Section III.A.8.3 requires determining the impact to "Day-Ahead Ancillary Service prices for each product in each hour," and the DA EIR price is set to the FER Price. Finally, Section III.A.8.5 clarifies that any mitigation imposed under Section III.A.8 does not

[340] The current provisions exist in Section III.A.5, which is a section of Appendix A that addresses Supply Offer mitigation rules. In this filing, the ISO also revises the title of Section III.A.5 to read "Supply Offer Mitigation" rather than simply "Mitigation."

[341] Marked Tariff, Section III.A.8.2.1(a) ("the expected value of the greater of (i) the hourly Real-Time Hub Price less the hourly Day-Ahead Ancillary Service Strike Price and (ii) zero").

[342] *Id.* at § III.A.8.2.1(b) ("the historical average of the estimated likelihood that the Real-Time Hub Price will be equal to or less than its expected value, multiplied by the greater of $100/MWh and the expected hourly Real-Time Hub Price").

extend beyond the offer-hour associated with a Day-Ahead Ancillary Services Offer that failed the conduct-and-impact test.

3. Proposed Revisions to Section III.A.3

The proposed revisions to Section III.A.3 and its subsections are intended to incorporate Day-Ahead Ancillary Services Offers into the IMM-consultation process that exists today, though the ISO proposes some revisions to clarify the process that exists today as well. For example, the revisions to Section III.A.3 add references to Benchmark Levels and the Day-Ahead Ancillary Services conduct test. The revisions also include the addition of "verifiable supporting" before information to make Section III.A.3's cost information requirements articulated consistently with how those requirements are articulated in current Section III.A.3.1, which uses the phrase "verifiable supporting information."

The Filing Parties propose to reorganize and revise the language of Section III.A.3.1 to add the necessary references to Day-Ahead Ancillary Services mitigation and to clarify the procedural requirements of this subsection. Current Section III.A.3.1 concerns consultation related to "an event that occurs within the 24 hour period prior to the Operating Day" that have impacted a supplier's costs. The Filing Parties propose to create separate paragraphs that will do the following: paragraph (a) will set forth consultation regarding Supply Offers, maintaining the current language related to Supply Offers; paragraph (b) will set forth consultation regarding Day-Ahead Ancillary Services Offers using similar language to paragraph (a) but adjusted as appropriate; paragraph (c) will retain the current language concerning consultation regarding fuel prices determined under Section III.A.7.5(e); and paragraph (d) will set forth the cost information requirements and timeline for consultation under Section III.A.3.1.

The proposed revisions to Section III.A.3.3 set forth a process for making available the Expected Close-Out Component and Avoidable Input Cost values to Market Participants such that they are able to calculate their conduct test thresholds, similar to how Reference Levels for energy offers are currently made available. Proposed revisions to Section III.A.3.4 incorporate adjustments to Avoidable Input Costs into the current Fuel Price Adjustment process. None of the proposed Section III.A.3.4 revisions are intended to change the current process, other than to ensure that both Reference Levels and Avoidable Input Costs are updated in tandem when a fuel price is submitted through this process.

4. Proposed Revisions to Section III.A.4

The proposed revisions to Section III.A.4 are intended to set forth the physical withholding mitigation rules for Day-Ahead Ancillary Services Offers. The proposed revisions to Sections III.A.4.1 and III.A.4.3 will ensure that the IMM's process for evaluating physical withholding of Day-Ahead Ancillary Services capabilities follows a similar process to the one employed for evaluating physical withholding in the energy markets, which includes: use of a similar concept of physical withholding; investigation through consultation; and application of an impact test, if necessary. The proposed revision to Section III.A.4.2.1 sets forth the conduct threshold described above in Section VI.F for Day-Ahead Ancillary Services Offers. The proposed revision to Section III.A.4.2.2 applies principles for considering deratings and outages when determining withheld ancillary services amounts that are similar to those applied with regard to generating capacity.

5. Proposed Revisions to Section III.A.15.2

The proposed revisions to Section III.A.15.2 incorporate costs associated with Day-Ahead Ancillary Services Offer mitigation into the cost-recovery filing process that currently exists with regard to energy market mitigation. Specifically, the revisions allow the supplier to seek recovery of "Day-Ahead Ancillary Services close-out or input costs" incurred as a result of mitigation when the applicable conditions are met. As described in Section VI.E above, the ISO proposes a new provision, which will be Section III.A.15.2(iii), to allow a Market Participant to "seek recovery of opportunity costs within the Day-Ahead Market as a result of mitigation applied to the Resource's Day-Ahead Ancillary Services Offer." The Filing Parties also propose revisions to existing Section III.A.15.2.1 that specify the documentation and information requirements associated with making a Section 205 filing for cost recovery. Although this specification is driven by the nature of Day-Ahead Ancillary Service Offers, these documentation and information requirements apply to all cost-recovery requests.

6. Proposed Revisions to Section III.A.17.2

Finally, the Filing Parties propose new Section III.A.17.2.5, which sets forth the IMM's ad hoc reporting requirement described in Section VIII above. Proposed Section III.A.17.2 details the IMM's responsibilities in preparing an ad hoc report and its continuing duties after completion of such ad hoc report.

X. STAKEHOLDER PROCESS

The DASI proposal was considered through the complete NEPOOL Participant Processes and supported by the Participants Committee. As detailed below, NEPOOL's three Technical Committees considered the proposed revisions separately before the Participants Committee acted upon the complete package of Tariff revisions.

1. NEPOOL Reliability Committee Review

The ISO presented its proposal to the Reliability Committee on two occasions, on June 13, 2023 and July 18, 2023. At the July 18 meeting, the Reliability Committee, based on a voice vote, unanimously voted in favor of recommending that the NEPOOL Participants Committee support the ISO's revisions to Sections I.2.2, III.1.5.2(a), III.9.5.3.1, and III.9.5.3.2.

2. NEPOOL Transmission Committee Review

The Transmission Committee considered aspects of the DASI proposal under its purview on June 23, 2023 and July 18, 2023. At its July 18 meeting, the Transmission Committee, based on a voice vote, unanimously voted in favor of recommending that the NEPOOL Participants Committee support revision to Section I.2.2.

3. NEPOOL Markets Committee Review

Between October 2022 and June 2023, the Markets Committee vetted and offered feedback to the ISO's DASI proposal. At its July 11, 2023 meeting, the Markets Committee, based on a show of hands vote, unanimously recommended that the Participants Committee support revisions to Section I.2.2 and Market Rule 1.[343]

4. NEPOOL Participants Committee Review

Subsequent to the Technical Committees' respective consideration and recommendation, at its August 3, 2023 meeting, the Participants Committee unanimously supported the DASI proposal through approval of the Consent Agenda.[344]

XI. REQUESTED EFFECTIVE DATE

The ISO requests that the Commission issue an order **within ninety (90) days** from the date of this filing accepting these Tariff changes as filed, without suspension or hearing, to be effective on March 1, 2025.

Although the ISO requests an effective date that is more than 480 days from the date of filing, the ISO requests that the Commission (1) issue an order on this filing within ninety (90) days of filing and (2) for good cause, waive the Commission's requirement in 18 C.F.R. § 35.3(a)(1) that all rate schedules or any part thereof must be filed with the Commission and posted not "more than one hundred-twenty days prior to the date on which the electric service is to commence and become effective."

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[343] The following abstentions were recorded: Generation Sector – 2; Supplier Sector – 1; and Alternative Resources Sector – 1. Note that no member opposed.

[344] The Consent Agenda for a 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 Participants Committee) to be taken by the Participants Committee through approval of a single motion at a meeting. Although voted as a single motion, all recommendations voted on as part of the Consent Agenda are deemed to have been voted on individually and independently. In this case, the Participants Committee's approval of the August 3, 2023 Consent Agenda included its support for the DASI proposal. Although no Participant objected to this item on the Consent Agenda, there were various abstentions. The following Participants' abstentions were attributed to the DASI proposal: Calpine Energy Services, LP, Granite Shore Companies, and Jericho Power LLC. For their part, Icetec Energy Services, Inc. and Maple Energy LLC abstained from the Consent Agenda vote due to an unrelated item on the agenda. Moreover, Mr. Jonathan Lamson abstained from the vote altogether.

The ISO is requesting an order within ninety days, despite the March 1, 2025 effective date, to allow sufficient time for the ISO to complete the necessary work both internally and with its vendors that is required to redesign the Day-Ahead market clearing engine to incorporate the proposed Day-Ahead Ancillary Services Market and the existing Day-Ahead Energy Market into a jointly optimized Day-Ahead Market. The ISO also requires significant time for the software development required to implement the new market power mitigation structure proposed in this filing. To be able to implement all aspects of the new market proposed in this filing, the ISO will need the entirety of the thirteen months between the end of January 2024 through February 2025 to complete implementation and testing of the proposed Day-Ahead Market. Approval within ninety (90) days will afford the ISO the time it needs to complete this process.

XII. ADDITIONAL SUPPORTING INFORMATION

Section 35.13 of the Commission's regulations generally requires public utilities to file certain cost and other information related to an examination of traditional cost-of-service rates.[345] However, the ISO is not a traditional investor-owned utility. Therefore, to the extent necessary, the Filing Parties request waiver of Section 35.13 of the Commission's regulations. Notwithstanding their request for waiver, the Filing Parties submit the additional information enumerated below in substantial compliance with the relevant provisions of Section 35.13.

<u>35.13(b)(1)</u> – Materials included herewith are as follows:

- This transmittal letter;
- Marked sections of the Tariff, reflecting the revisions effected by this filing;
- Clean sections of the Tariff, incorporating the revisions effected by this filing;
- Testimony of Dr. Matthew White in support of DASI;
- Testimony of Benjamin Ewing in support of DASI;
- Testimony of Dr. Parviz Alivand in support of DASI; and
- List of governors, utility regulatory agencies in Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island, and Vermont, and others to which a copy of this filing has been e-mailed.

<u>35.13(b)(2)</u> – As noted in Section VI above, the ISO requests that the revisions to Tariff proposed as part of DASI become effective on March 1, 2025.

<u>35.13(b)(3)</u> – Pursuant to Section 17.11(e) of the Participants Agreement, Governance Participants are being served electronically rather than by paper copy. The names and addresses

[345] 18 C.F.R. § 35.13 (2022).

of the Governance Participants are posted on the ISO's website at https://www.iso-ne.com/participate/participant-asset-listings/directory?id=1&type=committee. A copy of this transmittal letter and the accompanying materials have also been sent electronically to the governors and electric utility regulatory agencies for the six New England states that comprise the New England Control Area, to the New England Conference of Public Utility Commissioners, and to the Executive Director of the New England States Committee on Electricity. In accordance with Commission rules and practice, there is no need for the Governance Participants or the other entities described above to be included on the Commission's official service list in the captioned proceeding unless such entities become intervenors in this proceeding.

35.13(b)(4) – A description of the materials submitted pursuant to this filing is contained in Section VII of this transmittal letter.

35.13(b)(5) – The reasons for this filing are discussed in Sections III though IX of this transmittal letter.

35.13(b)(6) – The ISO's approval of the revisions to the Tariff is evidenced by this filing. The revisions to the Tariff reflect the results of the Participant Processes required by the Participants Agreement and the support of the Participants Committee.

35.13(b)(7) – The Filing Parties have no knowledge of any relevant expenses or costs of service that have been alleged or judged in any administrative or judicial proceeding to be illegal, duplicative, or unnecessary costs that are demonstrably the product of discriminatory employment practices.

35.13(b)(8) – A form of notice and electronic media are no longer required for filings in light of the Commission's Combined Notice of Filings notice methodology.

35.13(c)(1) – The Tariff changes herein do not modify a traditional "rate," and the statement required under this Commission regulation is not applicable to the instant filing.

35.13(c)(2) – The ISO does not provide services under other rate schedules that are similar to the wholesale, resale, and transmission services it provides under the Tariff.

35.13(c)(3) – No specifically assignable facilities have been or will be installed or modified in connection with the revisions filed herein.

XIII. CONCLUSION

For the foregoing reasons, the Filing Parties respectfully request that the Commission accept the proposed revisions to implement a Day-Ahead Ancillary Services Market and jointly optimized Day-Ahead Market as described herein without condition or change, to be effective on March 1, 2025.

Respectfully submitted,

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October 31, 2023

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.

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 Distributed Energy Resource participating as part of Demand Response Distributed Energy Resource Aggregation, a Settlement Only Distributed Energy Resource Aggregation, 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.

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.

Benchmark Scenario is an Economic Study reference scenario that is described in Section 17.2(a) of Attachment K to the OATT.

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, the demand reduction capability of a Demand Response Resource, or the demand reduction capability and energy injection capability of a Demand Response Distributed Energy Resource Aggregation.

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.

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.

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.

Cyber Security Exigency is a suspicious or malicious electronic act or event that compromises or attempts to compromise, or disrupts or attempts to disrupt, the ongoing operation of the ISO, the New England Markets, or reliability within the New England Control Area or other electrical facilities directly or indirectly connected to the New England Transmission System and (i) whose severity or nature reasonably requires that the ISO obtain expert assistance not normally called upon to counter such an electronic act or resolve such an event or (ii) whose nature requires the ISO to report such an electronic act or event pursuant to NERC Critical Infrastructure Protection Reliability Standards or applicable regulations promulgated by the Department of Homeland Security, the Department of Energy, or a federal agency with similar cybersecurity responsibilities (or any of their respective successor organizations or agencies).

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 Flexible Response Services and Day-Ahead Energy Imbalance Reserve.

Day-Ahead Ancillary Services Avoidable Input Cost is defined in Section III.A.8.2.2 of Appendix A of Market Rule 1.

Day-Ahead Ancillary Services Benchmark Level is defined in Section III.A.8.2 of Appendix A of Market Rule 1.

Day-Ahead Ancillary Services Expected Close-Out Component is defined in Section III.A.8.2.1 of Appendix A of Market Rule 1.

Day-Ahead Ancillary Services Market means the sale of and payment for Day-Ahead Ancillary Services 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 Ancillary Services Offer is an offer that may be submitted by Market Participants in the Day-Ahead Ancillary Services Market in accordance with Section III.1.8.1 of Market Rule 1, and that is used by the ISO to determine obligations for Day-Ahead Ancillary Services as described in Section III.3.2.1(a)(2) of Market Rule 1.

Day-Ahead Ancillary Services Strike Price is specified in Section III.1.8.2 of Market Rule 1.

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 Ancillary Services Market to help satisfy the Forecast Energy Requirement Demand Quantity described in Section III.1.8.4 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 the schedule of commitments for the purchase or sale of energy, purchase of demand reductions, payment of Congestion Costs, 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 Flexible Response Services means Day-Ahead Ten-Minute Spinning Reserve, Day-Ahead Ten-Minute Non-Spinning Reserve, and Day-Ahead Thirty-Minute Operating Reserve.

Day-Ahead Flexible Response Services Demand Quantities means Day-Ahead Ten-Minute Spinning Reserve Demand Quantity, Day-Ahead Total Ten-Minute Reserve Demand Quantity, Day-Ahead Minimum Total Reserve Demand Quantity, and Day-Ahead Total Reserve Demand Quantity.

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 Market means the jointly optimized Day-Ahead Energy Market and Day-Ahead Ancillary Services Market.

Day-Ahead Minimum Total Reserve Demand Quantity is described in Section III.1.8.3(c) of Market Rule 1.

Day-Ahead Prices means the ~~Locational Marginal P~~prices resulting from the Day-Ahead ~~Energy~~ Market as described in Section III.2.6 of Market Rule 1.

Day-Ahead Ten-Minute Non-Spinning Reserve is a form of ten-minute reserve capability that is procured in the Day-Ahead Ancillary Services Market based on the system-wide requirements described in Section III.1.8.3 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 Ancillary Services Market based on the system-wide requirements described in Section III.1.8.3 of Market Rule 1.

Day-Ahead Ten-Minute Spinning Reserve Demand Quantity is described in Section III.1.8.3(a) of Market Rule 1.

Day-Ahead Ten-Minute Spinning Reserve Obligation is described 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 Ancillary Services Market based on the system-wide requirements described in Section III.1.8.3 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 Ten-Minute Reserve Demand Quantity is described in Section III.1.8.3(b) of Market Rule 1.

Day-Ahead Total Reserve Demand Quantity is described in Section III.1.8.3(d) 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 Distributed Energy Resource Aggregation (DRDERA) is a type of Distributed Energy Resource Aggregation that is described in additional detail in Section III.6.5.

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 Energy Capacity Resource (DECR) means an Existing Distributed Energy Capacity Resource or a New Distributed Energy Capacity Resource.

Distributed Energy Resource (DER) is any resource located on the distribution system, any subsystem thereof or behind a customer meter that is capable of providing energy injection, energy withdrawal, regulation, or demand reduction.

Distributed Energy Resource Aggregation (DERA) is an aggregation of Distributed Energy Resources that is registered under Section III.6.7 and is described in additional detail in Section III.6.

Distributed Energy Resource Aggregator (DER Aggregator) is a Market Participant that aggregates one or more Distributed Energy Resources for participation in a Distributed Energy Resource Aggregation and serves as the Lead Market Participant for a Distributed Energy Resource Aggregation.

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, Existing Demand Capacity Resources, and Existing Distributed Energy 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 or Economic Studies are studies described in Section 17 of Attachment K to the OATT that are used to examine situations where potential regulated transmission solutions, market responses, or investments could result in (i) a net reduction in total production cost to supply system load based on the factors specified in Attachment N of the OATT, (ii) reduced congestion, or (iii) the integration of new resources or loads, or both, on an aggregate or regional basis.

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 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 Distributed Energy Capacity Resource is a type of Distributed Energy Capacity Resource participating in the Forward Capacity Market, as defined in Section III.13.1.4A.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.1.8.4 of Market Rule 1.

Forecast Energy Requirement Penalty Factor is a rate, in $/MWh, that is used within the Day-Ahead Market security-constrained economic commitment and dispatch process to reflect the value of forecast energy requirement shortages and is defined in Section III.2.6.2(d) of Market Rule 1.

Forecast Energy Requirement Price is determined in accordance with Section III.2.6.2(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. As described in Section III.9.1, the final Forward Reserve Procurement Period shall run from October 1, 2024 through February 28, 2025.

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 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 or an aggregation of wind, solar, run of river hydro and other renewable resources 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, Demand Reduction Offers, ~~or~~ Baseline Deviation Offers, or Day-Ahead Ancillary Services 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-Side Relationship Certification is a certification described in Section III.A.21.1.3 that a Project Sponsor submits as part of the New Capacity Qualification Package, New Demand Capacity Resource Qualification Package, or New Distributed Energy Capacity Resource Qualification Package to demonstrate that the New Capacity Resource should not be subject to buyer-side market power review.

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.

Longer-Term Transmission Study is a study conducted by the ISO pursuant to the process set out in Section 16 of Attachment K of the OATT. The 2050 Transmission Study shall be the first Longer-Term Transmission Study.

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 Needs Scenario is an Economic Study reference scenario that is described in Section 17.2(b) of Attachment K to the OATT.

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 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 Award Limit is a parameter that may be submitted as part of a Day-Ahead Ancillary Services Offer, as described in Section III.1.8.1, that expresses the maximum total megawatt-hours of Day-Ahead energy offered or bid and Day-Ahead Ancillary Services offered for the next Operating Day.

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 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 ninth 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 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 to be economically viable given reasonable expectations of the energy and ancillary services revenues under long-term equilibrium conditions.

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, New Demand Capacity Resource, or New Distributed Energy 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, a New Demand Capacity Resource Show of Interest Form, or a New Distributed Energy 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 Distributed Energy Capacity Resource is a type of Distributed Energy Capacity Resource participating in the Forward Capacity Market, as defined in Section III.13.1.4A.1 of Market Rule 1.

New Distributed Energy Capacity Resource Qualification Package is the information that a Project Sponsor must submit, in accordance with Section III.13.1.4A.1.1.2 of Market Rule 1, for each resource that it seeks to offer in the Forward Capacity Auction as a New Distributed Energy Capacity Resource.

New Distributed Energy Capacity Resource Show of Interest Form is described in Section III.13.1.4A.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.21.3.

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.

Permanent De-list Bid is a bid that may be submitted by an Existing Generating Capacity Resource, Existing Import Capacity Resource, Existing Demand Capacity Resource, or Existing Distributed Energy 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.

Policy Scenario is an Economic Study reference scenario that is described in Section 17.2(c) of Attachment K to the OATT.

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, New Demand Capacity Resource, or New Distributed Energy 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 an 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 SATOA Obligation is defined in Section III.3.2.1(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). 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. A Network Customer's Monthly Regional Network Load shall be calculated in accordance with Section II.21.2 of the OATT.

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 that are used within the Day-Ahead Market security-constrained economic commitment and dispatch process to reflect the value of Day-Ahead Flexible Response Services shortages and defined in Section III.2.6.2(c) 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, a Demand Response Resource, a Settlement Only Distributed Energy Resource Aggregation, or a Demand Response Distributed Energy Resource Aggregation.

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, Existing Demand Capacity Resource, or Existing Distributed Energy 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.

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 officer.

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 Distributed Energy Resource Aggregation (SODERA) is a type of Distributed Energy Resource Aggregation and is described in additional detail in Section III.6.6.

Settlement Only Resources are generators of less than 5 MW of maximum net output when operating at any temperature at or above zero degrees Fahrenheit, that meet the metering, interconnection and other requirements 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.

Solar High Limit is the estimated power output (MW) of a solar Generator Asset given the Real-Time solar and weather conditions, taking into account equipment outages, and absent any self-imposed reductions in power output or any reduction in power output as a result of a Dispatch Instruction, calculated in the manner described in the ISO Operating Documents.

Solar Plant Future Availability is the forecasted Real-Time High Operating Limit of a solar Generator Asset, calculated in the manner described in the ISO Operating Documents.

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, each asset of which: receives a revenue source, other than revenues from ISO-administered markets, that is supported by a government-regulated rate, charge, or other regulated cost recovery mechanism, and; qualifies as a renewable, clean, zero carbon, or alternative energy asset under a renewable energy portfolio standard, clean energy standard, decarbonization or net-zero carbon standard, alternative energy portfolio standard, renewable energy goal, clean energy goal, or decarbonization or net-zero carbon goal enacted by federal or New England state statute, regulation, or executive or administrative order and as a result of which the asset receives the revenue source.

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.

Stakeholder-Requested Scenario is an Economic Study reference scenario that is described in Section 17.2(d) of Attachment K to the OATT.

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.

State-identified Requirement refers to a legal requirement, mandate or policy of a New England state or local government that forms the basis for a Longer-Term Transmission Study request submitted to the ISO pursuant to the process set out in Section 16 of Attachment K of the OATT.

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, Existing Demand Capacity Resource, or Existing Distributed Energy 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 as Transmission-Only Asset (SATOA) is electric storage equipment that: (1) is connected to or to be connected to Pool Transmission Facilities in the New England Transmission System at a voltage level of 115 kV or higher; (2) the ISO approved to be included in the Regional System Plan and RSP Project List as a regulated transmission solution and Pool Transmission Facility pursuant to the regional system planning processes in Attachment K of the OATT; and (3) is capable of receiving energy only from the Pool Transmission Facilities and storing the energy for later injection to the Pool Transmission Facilities.

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.

Wind High Limit is the estimated power output (MW) of a wind Generator Asset given the Real-Time weather conditions, taking into account equipment outages, and absent any self-imposed reductions in power output or any reduction in power output as a result of a Dispatch Instruction, calculated in the manner described in the ISO Operating Documents.

Wind Plant Future Availability is the forecasted Real-Time High Operating Limit of a wind Generator Asset, calculated in the manner described in the ISO Operating Documents.

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.

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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. The ISO shall use a joint optimization process to serve Day-Ahead Market energy requirements and Day-Ahead Ancillary Services requirements, as described in Section III.1.10.8(a).

(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 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 LMP-Based 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.1.7.9 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.1.7.9A 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.1.7.10 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 potential referral under Section III.A.19.

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.1.7.21 SATOA Participation in Markets: A Node will be established for each SATOA. A Market Participant's market activity, transactions, and actions taken at a SATOA's Node and a SATOA's participation in the New England Markets shall be limited to those necessary to consume or inject energy from or to PTF for any period, magnitude, and duration identified as necessary to: (1) address the applicable system needs or provide the transmission function for which the SATOA was selected as the preferred solution; or (2) as specified in the ISO New England Operating Documents, avoid or mitigate Load Shedding after all available Dispatchable Resources that can effectively provide relief to avoid or mitigate the Load Shedding have been dispatched.

III.1.8 Day-Ahead Ancillary Services and Forecast Energy Requirement~~[Reserved.~~.]

III.1.8.1 Day-Ahead Ancillary Services Offers.

Market Participants may submit Day-Ahead Ancillary Services Offers for the Operating Day in the Day-Ahead Ancillary Services Market as specified in this Section III.1.8.1.

(a) Each Day-Ahead Ancillary Services Offer shall be associated with a specific Generator Asset, Demand Response Resource, or DARD for which the Market Participant has submitted a corresponding

Supply Offer, Demand Reduction Offer, or Demand Bid in the Day-Ahead Energy Market for the same hour of the Operating Day.

(b) Each Day-Ahead Ancillary Services Offer shall specify: (i) the hour of the Operating Day for which the Day-Ahead Ancillary Services Offer applies; (ii) product-specific offer prices, in $/MWh, that are greater than or equal to zero for the Day-Ahead Ancillary Services; and (iii) a single offer quantity, in MWh, that is greater than or equal to zero. The offer prices for the Day-Ahead Ancillary Services shall not exceed the Forecast Energy Requirement Penalty Factor as specified in Section III.2.6.2(d) of this Market Rule 1. The offer quantity shall not exceed the Economic Maximum Limit specified in the associated Supply Offer, the Maximum Reduction specified in the associated Demand Reduction Offer, or the Maximum Consumption Limit specified in the associated Demand Bid.

(c) As part of its Day-Ahead Ancillary Services Offer, a Market Participant is permitted to specify a Maximum Daily Award Limit quantity, in MWh, that is greater than or equal to zero.

(d) For each hour of the Operating Day, a Market Participant may submit only one Day-Ahead Ancillary Services Offer associated with a specific Generator Asset, Demand Response Resource, or DARD.

(e) Day-Ahead Ancillary Services Offers shall be submitted by the offer submission deadline for the Day-Ahead Market specified in Section III.1.10.1A of this Market Rule 1. A Day-Ahead Ancillary Services Offer shall not remain in effect for subsequent Operating Days.

III.1.8.2 Day-Ahead Ancillary Services Strike Price.

(a) For each hour of the Operating Day, the ISO shall specify the Day-Ahead Ancillary Services Strike Price in $/MWh. The value of the Day-Ahead Ancillary Services Strike Price represents an amount that is the greater of (i) $10/MWh greater than a forecast of the expected hourly Real-Time Hub Price for such hour of the Operating Day and (ii) zero.

(b) The forecast used to determine the Day-Ahead Ancillary Services Strike Price shall be based on a publicly-available forecasting algorithm developed by the ISO. The ISO shall describe the publicly-available forecasting algorithm to Market Participants and shall periodically review and assess the efficacy of the forecasting algorithm. The ISO shall notify stakeholders of any potential revisions to the ISO's forecasting algorithm prior to implementing such revisions.

(c) In the event that the ISO is not able to utilize the ISO-developed forecasting algorithm described in subsection (b) above due to hardware, software, or telecommunications problems, human error, or exigent circumstances not contemplated by this market rule, the ISO shall determine the Day-Ahead Ancillary Services Strike Price using the best forecast available and shall disclose the use of such substitute forecast to Market Participants as soon as practicable.

III.1.8.3 Day-Ahead Flexible Response Services Demand Quantities.

The Day-Ahead Ancillary Services Market shall endeavor to procure the Day-Ahead Flexible Response Services Demand Quantities specified in this Section III.1.8.3.

(a) For each hour of the Operating Day, the Day-Ahead Ten-Minute Spinning Reserve Demand Quantity shall be equal to the Ten-Minute Spinning Reserve Requirement projected Day-Ahead.

(b) For each hour of the Operating Day, the Day-Ahead Total Ten-Minute Reserve Demand Quantity shall be equal to the Ten-Minute Reserve Requirement projected Day-Ahead.

(c) For each hour of the Operating Day, the Day-Ahead Minimum Total Reserve Demand Quantity shall be equal to the Minimum Total Reserve Requirement projected Day-Ahead.

(d) For each hour of the Operating Day, the Day-Ahead Total Reserve Demand Quantity shall be equal to the Total Reserve Requirement projected Day-Ahead.

III.1.8.4 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 load in the New England Control Area produced pursuant to Section III.1.10.1A(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 and Demand Reduction 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 thea 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 sell ancillary services through the New England Markets at 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 and Day-Ahead Ancillary Services Market Scheduling.

Market Participants may submit offers and bids in the Day-Ahead ~~Energy~~ Market until 10:30 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 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</u>

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:

$$DRTP = P_{th} X \text{—} \frac{FPI_c}{FPI_h}$$

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) **Day-Ahead Ancillary Services Offers** – Market Participants selling into the New England Markets from Generator Assets or Demand Response Resources or participating in the New England Markets with DARDs, and that have submitted Supply Offers, Demand Reduction Offers, or Demand Bids for the following Operating Day, as described in subsections (c), (d), and (e) of this Section III.1.10.1A, may submit Day-Ahead Ancillary Services Offers for the following Operating Day. Day-Ahead Ancillary Services Offers shall be submitted to the ISO in accordance with Section III.1.8.1 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, ancillary services, 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 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 offers and requirements, and the Forecast Energy Requirement Demand Quantity.

(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 and storing the energy for later injection of electricity into 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 any 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 incapable of receiving and storing electricity from the grid may participate in the New England Markets as a Continuous Storage Facility, so long as that facility satisfies all Continuous Storage Facility registration and participation requirements that are not solely related to consumption capability. Notwithstanding Section III.1.10.6(a), Section III.1.10.6(c), and any other related provisions, such non-consuming storage facilities shall not be required to:

(i) be capable of consuming at least 0.1 MW from the grid; or

(ii) be capable of modifying consumption responsive to Dispatch Instructions.

(e) 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 energy shall not qualify as, or be billed to, a Storage DARD if that facility's charging energy is included in another 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 energy.

(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.

(f) 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.

(g) 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.

(h) 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.)

(i) 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.

(j) 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~~Scheduling Considerations.

(a) ~~The ISO shall use its best efforts to determine (i) 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) 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 scheduling the Day-Ahead Market, the ISO shall use its best efforts to determine the security-constrained economic commitment and dispatch that jointly optimizes: (i) Demand Bids, Decrement Bids, Demand Reduction Offers, Supply Offers, Increment Offers, and External Transactions, for energy; (ii) Day-Ahead Ancillary Services Offers to satisfy the Day-Ahead Flexible Response Services Demand Quantities; and (iii) Supply Offers, Demand Reduction Offers, External Transactions, and Day-Ahead Ancillary Services Offers to satisfy the Forecast Energy Requirement Demand Quantity.

In making the~~se~~ determination~~s~~ specified in this subsection (a), the ISO shall take into account, as applicable: (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 ancillary services~~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~~ the operational capabilities of any Resource to adjust the output, consumption, or demand reduction within the operating characteristics and parameters specified in the Market Participant's Offer Data, Supply Offer, Demand Reduction Offer, or Demand Bid and any audited values of such operating characteristics and parameters; (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.~~

In scheduling the Day-Ahead Market, the following limitations shall apply:

(i) For purposes of satisfying the Day-Ahead Flexible Response Services Demand Quantities specified in Sections III.1.8.3(a) through (d), the ISO shall not take into account a Day-Ahead Ancillary Services Offer unless the Generator Asset, Demand Response Resource, or DARD associated with the Day-Ahead Ancillary Services Offer meets the eligibility requirements enumerated in Section III.1.7.19.1.

(ii) For purposes of satisfying the Forecast Energy Requirement Demand Quantity specified in Section III.1.8.4, the ISO shall not take into account a Day-Ahead Ancillary Services Offer unless the offer is associated with a Generator Asset or Demand Response Resource that meets the following conditions:

(1) The Generator Asset or Demand Response Resource is, for the applicable hour, either scheduled for energy in the Day-Ahead Energy Market or is a Fast Start Generator or Fast Start Demand Response Resource.

(2) The Generator Asset or Demand Response Resource is not designated as constrained by transmission limitations, as described in Section III.1.7.19.1(3).

~~-~~(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 ~~E~~energy and ancillary services 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 and ancillary services scheduled in the Day-Ahead ~~Energy~~ Market based upon ~~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, and nuclear-powered 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, solar, 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 Market Participant may elect, but is not required, to have a wind, solar, 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.

(ii) 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.

(c) Wind and solar Generator Assets that are not Settlement Only Resources shall electronically transmit meteorological and forced outage data, as specified below, to the ISO, over a secure network, using the protocol specified in the ISO Operating Documents, for the development and deployment of wind and solar power production forecasts.

Wind Generator Assets that are not Settlement Only Resources shall provide the ISO with the following site-specific meteorological and forced outage data in the manner described in the ISO Operating Documents:

(i) at least once every 30 seconds: wind speed, and wind direction;

(ii) at least once every 5 minutes: ambient air temperature, standard deviation of ambient air temperature, ambient air pressure, standard deviation of ambient air pressure, ambient air relative humidity, and standard deviation of ambient air relative humidity;

(iii) at least once every 5 minutes: Real-Time High Operating Limit, Wind High Limit, wind turbine counts; and

(iv) at least once every hour at the top of the hour for the next 48 hours and by 1000 each day for the next 49 to 168 hours: Wind Plant Future Availability.

Solar Generator Assets that are not Settlement Only Resources shall provide the ISO with the following site-specific meteorological and forced outage data in the manner described in the ISO Operating Documents:

(i) at least once every 30 seconds: irradiance;

(ii) at least once every 5 minutes: ambient air temperature, standard deviation of ambient air temperature, ambient air pressure, standard deviation of ambient air pressure, ambient air relative humidity, standard deviation of ambient air relative humidity, wind speed, and wind direction;

(iii) at least once every 5 minutes: Real-Time High Operating Limit, and Solar High Limit; and

(iv) at least once every hour at the top of the hour for the next 48 hours and by 1000 each day for the next 49 to 168 hours: Solar Plant Future Availability.

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. 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 Market.

III.2.2 General.

The ISO shall determine the least cost security-constrained economic~~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, Day-Ahead Ancillary Services prices, and the Forecast Energy Requirement Price will be calculated based on ~~the unit~~ the joint optimization process described in Section III.1.10.8(a) utilizing~~commitment and economic dispatch and~~ the prices of ~~energy~~ offers and bids, the Forecast Energy Requirement Penalty Factor as specified in Section III.2.6.2(d) when applicable, and Reserve Constraint Penalty Factors as specified in Section III.2.6.2(c) when applicable. 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.

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, 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 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 submitted to the ISO and scheduled in the Day-Ahead Energy Market.~~ Day-Ahead Locational Marginal Prices shall be determined on the basis of the Day-Ahead Market security-constrained economic commitment and dispatch described in Section III.1.10.8(a) and

~~Such prices shall be determined~~ in accordance with the provisions of this Section applicable to the Day-Ahead Energy Market. ~~and~~ Such prices 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 a joint~~n~~ optimization method ~~to minimize energy~~ consistent with Section III.1.10.8(a)~~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 Day-Ahead Ancillary Services 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 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 cost of serving ~~energy 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.

The ISO shall calculate hourly Day-Ahead Prices for additional requirements in the Day-Ahead Market as described in this Section III.2.6.2.

(a) **Day-Ahead Flexible Response Services Clearing Prices.**

(i) The clearing price for Day-Ahead Thirty-Minute Operating Reserve shall be the incremental cost, as measured by the change in the Day-Ahead Market security-constrained economic dispatch objective value, to satisfy:

(1) the next increment of Day-Ahead Minimum Total Reserve Quantity, if the cost of such next increment is greater than or equal to the Reserve Constraint Penalty Factor applicable to the Day-Ahead Total Reserve Demand Quantity; or,

(2) if Section III.2.6.2(a)(i)(1) is inapplicable, the next increment of Day-Ahead Total Reserve Demand Quantity.

(ii) The clearing price for Day-Ahead Ten-Minute Non-Spinning Reserve shall be the sum of (1) the incremental cost, as measured by the change in the Day-Ahead Market security-constrained economic dispatch objective value, to satisfy the next increment of the Day-Ahead Total Ten-Minute Reserve Demand Quantity, and (2) the clearing price for Day-Ahead Thirty-Minute Operating Reserve.

(iii) The clearing price for Day-Ahead Ten-Minute Spinning Reserve shall be the sum of (1) the incremental cost, as measured by the change in the Day-Ahead Market security-constrained economic dispatch objective value, to satisfy the next increment of Day-Ahead Ten-Minute Spinning Reserve, and (2) the clearing price for Day-Ahead Ten-Minute Non-Spinning Reserve.

(iv) If the Day-Ahead Market does not clear sufficient Day-Ahead Flexible Response Services to satisfy one or more of the Day-Ahead Flexible Response Services Demand Quantities, the Day-Ahead Flexible Response Services clearing prices shall be set based upon the applicable Reserve Constraint Penalty Factors, as described by Section III.2.6.2(c)(i) through (iv).

(b) **Forecast Energy Requirement Price**.

(i) The Forecast Energy Requirement Price shall be the marginal cost, as measured by the change in the Day-Ahead Market security-constrained economic dispatch objective value, to satisfy the next increment of the Forecast Energy Requirement Demand Quantity.

(ii) The Forecast Energy Requirement Price shall be based upon the Forecast Energy Requirement Penalty Factor specified by Section III.2.6.2(d) when any one or some combination of the following occurs:

(1) The Day-Ahead Market does not clear sufficient energy and Day-Ahead Energy Imbalance Reserve to satisfy the Forecast Energy Requirement Demand Quantity.

(2) The Day-Ahead Locational Marginal Prices are set pursuant to Section III.2.6.1(b).

(c) **Reserve Constraint Penalty Factors in the Day-Ahead Market**. The Day-Ahead Market scheduling pursuant to Section III.1.10.8(a), 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 Minimum Total 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 Reserve Demand Quantity shall be equal to the Real-Time Total Reserve Requirement Reserve Constraint Penalty Factor specified in Section III.2.7A.

(d) **Forecast Energy Requirement Penalty Factor**. The Day-Ahead Market scheduling pursuant to Section III.1.10.8(a), and the Day-Ahead Prices specified in Section III.2.6, shall respect the Forecast Energy Requirement Penalty Factor applicable to the Forecast Energy Requirement Demand Quantity. The Forecast Energy Requirement Penalty Factor shall be set at $2,575/MWh.

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 in Real-Time 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 ~~R~~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 and Day-Ahead Ancillary Services 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 and Day-Ahead Ancillary Services 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 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 Ancillary Services Market Obligations** – Each Market Participant with a Day-Ahead Ancillary Services Offer that is accepted by the ISO in the Day-Ahead Ancillary Services 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 Day-Ahead Ancillary Services 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 Day-Ahead Ancillary Services Offer quantity that contributes to satisfying the Day-Ahead Total Ten-Minute Reserve Demand Quantity, and that same Day-Ahead Ancillary Services 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 Day-Ahead Ancillary Services Offer quantity that contributes to satisfying the Day-

Ahead Total Reserve Demand Quantity, and that same Day-Ahead Ancillary Services 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 Energy Imbalance Reserve Obligation** – A Market Participant with an accepted Day-Ahead Ancillary Services 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 plus the Real-Time SATOA 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.

(vi) **Real-Time SATOA Obligation** – Each PTO shall have for each settlement interval a Real-Time SATOA Obligation for energy at each Location equal to the sum of: (1) the MWhs of energy, where such MWhs of energy shall have positive value, provided by SATOAs at that Location; and (2) the MWhs of load, where such MWhs of load shall have a negative value, consumed by SATOAs at that Location.

(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 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 Ancillary Services Market Credit** – 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).

(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).

(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).

(iv) **Day-Ahead Energy Imbalance Reserve Credit** – Each MWh of Day-Ahead Energy Imbalance Reserve Obligation shall be credited the Forecast Energy Requirement Price calculated in accordance with Section III.2.6.2(b).

(q)(2) **Day-Ahead Ancillary Services Market Close-Out Charge** – Each Market Participant with a Day-Ahead Ancillary Services obligation shall receive a charge as follows:

(i) **Day-Ahead Flexible Response Services Charge** – Each MWh of Day-Ahead Ten-Minute Spinning Reserve Obligation, Day-Ahead Ten-Minute Non-Spinning Reserve Obligation, and Day-Ahead Thirty-Minute Operating 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 Day-Ahead Ancillary Services Strike Price for the hour, and (b) zero.

(ii) **Day-Ahead Energy Imbalance Reserve Charge** – Each MWh of Day-Ahead Energy Imbalance Reserve Obligation shall be charged the close-out charge rate determined in accordance with Section III.3.2.1(q)(2)(i).

(q)(3) **Allocation of Day-Ahead Flexible Response Services Credits/Charges**

(i) The sum total credits calculated in accordance with Sections III.3.2.1(q)(1)(i) through (iii) for Day-Ahead Flexible Response Services 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 at all External Nodes (but not excluding the Real-Time Load Obligation incurred by Capacity Export Through Import Constrained Zone Transactions or FCA Cleared Export Transactions), and 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 Flexible Response Services 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 at all External Nodes (but not excluding the Real-Time Load Obligation incurred by Capacity Export Through Import Constrained Zone Transactions or FCA Cleared Export Transactions), and excluding Real-Time Load Obligation incurred by Storage DARDs.

(q)(4) **Allocation of Forecast Energy Requirement and Day-Ahead Energy Imbalance Reserve Credits/Charges**

(i) **Forecast Energy Requirement Credit for Generator Assets and Demand Response Resources** – Each Market Participant with a Generator Asset or Demand Response Resource scheduled in the Day-Ahead Energy Market shall be credited the Forecast Energy Requirement Price, calculated in accordance with Section III.2.6.2(b), for each MWh of the resource's Day-Ahead energy obligation.

(ii) **Forecast Energy Requirement Credit for External Transaction Purchases** – Each Market Participant with an External Transaction purchase scheduled in the Day-Ahead Energy Market for which a corresponding External Transaction also has been properly submitted in the Real-Time Energy Market and submitted in the appropriate external Control Area shall be credited the Forecast Energy Requirement Price, calculated in accordance with Section III.2.6.2(b), for the lesser of (a) each MWh of the Day-Ahead energy obligation associated with the External Transaction and (b) each MWh offered for the corresponding External Transaction in the Real-Time Energy Market.

(iii) **Forecast Energy Requirement and Day-Ahead Energy Imbalance Reserve Charges** – The total amount credited in accordance with Sections III.3.2.1(q)(4)(i), III.3.2.1(q)(4)(ii), and III.3.2.1(q)(1)(iv) shall be charged on an hourly basis as follows:

a. Each Market Participant with an External Transaction sale scheduled in the Day-Ahead Energy Market shall receive a charge at the Forecast Energy Requirement Price for each MWh of such External Transaction sale.

b. For the difference between the total amount credited and the total amount charged to Market Participants with External Transaction sales scheduled in the Day-Ahead Energy Market as described in this subsection (iii), Market Participants shall receive a charge based on their pro rata share of the sum of all Market Participants' Real-Time Load Obligation, excluding Real-Time Load Obligation incurred at all External Nodes, and excluding Real-Time Load Obligation incurred by Storage DARDs.

(iv) **Day-Ahead Energy Imbalance Close-Out Credits** – The sum total close-out charges calculated in accordance with Section III.3.2.1(q)(2)(ii) for Day-Ahead Energy Imbalance 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 at all External Nodes, and excluding Real-Time Load Obligation incurred by 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, Load Asset, and SATOA 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), each Asset Related Demand, and each SATOA 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 of an RBA form for a Meter Data Error as defined in Section 6.3.1 of the ISO New England Billing Policy, 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. 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, 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.9 Forward Reserve Market

The Forward Reserve Market is a market to procure TMNSR and TMOR on a forward basis to satisfy Forward Reserve requirements.

III.9.1 Forward Reserve Market Timing.

A Forward Reserve Auction will be held approximately two months in advance of each Forward Reserve Procurement Period. The Forward Reserve Auction input parameters and assumptions will be evaluated, published and reviewed with Market Participants prior to the Forward Reserve Auction. The final Forward Reserve Auction will be held approximately two months in advance of the final Forward Reserve Procurement Period as described in this Section III.9.1, and no Forward Reserve Auctions shall be conducted thereafter.

The Forward Reserve Procurement Periods shall be the Winter Capability Period (October 1 through May 31) or the Summer Capability Period (June 1 through September 30), as applicable. The final Forward Reserve Procurement Period shall run from October 1, 2024 through February 28, 2025.

The Forward Reserve Delivery Period shall be hour ending 0800 through hour ending 2300 for each weekday of the Forward Reserve Procurement Period excluding those weekdays that are defined as NERC holidays.

III.9.2 Forward Reserve Requirements.

The ISO shall conduct an advance purchase of capability to satisfy the expected Forward Reserve requirements for the system and each Reserve Zone as calculated by the ISO in accordance with the following procedures and as specified more fully in the ISO New England Manuals. The Forward Reserve requirements will be specified as part of the Forward Reserve Auction parameters and will be published and reviewed with Market Participants prior to each Forward Reserve Auction.

III.9.2.1 System Forward Reserve Requirements.

The Forward Reserve requirements for the New England Control Area will be based on the forecast of the first and second contingency supply losses for the next Forward Reserve Procurement Period and will consist of the following:

(i) One half of the forecasted first contingency supply loss will be specified as the minimum forward ten-minute reserve requirement to be purchased.

(ii) The minimum forward ten-minute reserve requirement described in subsection (i) will be increased if system conditions forecasted for the Forward Reserve Procurement Period indicate that the TMNSR available during the period would otherwise be insufficient to meet Real-Time Operating Reserve requirements. The increase shall be calculated to account for: (a) any historical under-performance of Resources dispatched in response to a System contingency and (b) the likelihood that more than one half of the forecasted first contingency supply loss will be satisfied using TMNSR.

(iii) The minimum forward ten-minute reserve requirement plus one half of the second contingency supply loss will be specified as the minimum forward total reserve requirement to be purchased.

(iv) The minimum forward total reserve requirement described in subsection (iii) will be increased by an amount of Replacement Reserve as specified in ISO New England Operating Procedure No. 8.

The requirements specified above, further adjusted to respect the additional provisions described in Section III.9.2.2, represent the set of requirements that will be input into the Forward Reserve Auction.

III.9.2.2 Zonal Forward Reserve Requirements.

Zonal Forward Reserve requirements will be established for each Reserve Zone. The zonal Forward Reserve requirements will reflect the need for 30-minute contingency response to provide 2nd contingency protection for each import constrained Reserve Zone. The zonal Forward Reserve requirements can be satisfied only by Resources that are located within a Reserve Zone and that are capable of providing 30-minute or higher quality reserve products.

The ISO shall establish the zonal Forward Reserve requirements based on a rolling, two-year historical analysis of the daily peak hour operational requirements for each Reserve Zone for like Forward Reserve Procurement Periods. The ISO will commence the analysis on February 1 or the first business day thereafter for the subsequent summer Forward Reserve Procurement Period and on June 1 or the first business day thereafter for the subsequent winter Forward Reserve Procurement Period.

These daily peak hour requirements will be aggregated into daily peak hour frequency distribution curves and the MW value at the 95th percentile of the frequency distribution curve for each Reserve Zone will establish the zonal requirement.

In the event of a change in the configuration of the transmission system or the addition, deactivation or retirement of a major Generator Asset, Dispatchable Asset Related Demand or Demand Response Resource the rolling two-year historical analysis will be calculated in a manner that reflects the change in configuration of the transmission system or the addition, deactivation or retirement of a major Generator Asset, Dispatchable Asset Related Demand or Demand Response Resource as of the commencement date of the analysis provided that the following conditions are met:

(a) Change in Configuration of the Transmission System

Any change in the configuration of the transmission system must have been placed in service and released for dispatch on or before December 31 for inclusion in the analysis for setting the zonal Forward Reserve requirements for the subsequent summer Forward Reserve Procurement Period or on or before April 30 for inclusion in the analysis for setting the zonal Forward Reserve requirements for the subsequent winter Forward Reserve Procurement Period.

If the change in the configuration of the transmission system consists of a new facility or upgrade of an existing facility, the facility must have operated at an availability level of at least 95% for the period beginning with its in service date and ending on January 31 prior to the summer Forward Reserve Procurement Period or ending on May 31 prior to the winter Forward Reserve Procurement Period.

(b) Addition, Deactivation or Retirement of a Major Generating Resource, Dispatchable Asset Related Demand or Demand Response Resource.

For the addition of a new Generator Asset, Dispatchable Asset Related Demand, or Demand Response Resource, the Resource must be placed in service and released for dispatch on or before December 31 for inclusion in the analysis for setting the zonal Forward Reserve requirements for the subsequent summer Forward Reserve Procurement Period or on or before April 30 for inclusion in the analysis for setting the zonal Forward Reserve requirements for the subsequent winter Forward Reserve Procurement Period. For the deactivation or retirement of a Generator Asset, Dispatchable Asset Related Demand or Demand Response Resource, the Resource must have been removed from service on or before January 31 for inclusion in the analysis for setting the zonal Forward Reserve requirements for the subsequent summer

Forward Reserve Procurement Period or on or before May 31 for inclusion in the analysis for setting the zonal Forward Reserve requirements for the subsequent winter Forward Reserve Procurement Period.

The modified historical data set will be composed of actual data used in the operation of the reconfigured system and historical (pre-reconfiguration) data adjusted for the impact of the system reconfiguration. Pre-reconfiguration data will be revised by substituting values from the historical data set that are no longer valid with corresponding values used in the operation of the reconfigured system.

The zonal Forward Reserve requirements will be recalculated using the modified historical data set until the rolling two-year historical data set reflects a common system configuration.

III.9.3 Forward Reserve Auction Offers.

Forward Reserve Auction Offers for TMNSR and TMOR shall be (a) made on a $/MW-month basis, (b) made on a Reserve Zone specific basis, (c) made on a non-Resource specific basis and (d) shall be less than or equal to the Forward Reserve Offer Cap. Forward Reserve Auction Offers shall be submitted to the ISO by Market Participants. The Market Participants are responsible for complying with the requirements of this Section III.9 if the Forward Reserve Auction Offer is accepted.

III.9.4 Forward Reserve Auction Clearing and Forward Reserve Clearing Prices.

The Forward Reserve Auction shall simultaneously clear Forward Reserve Auction Offers to meet the Forward Reserve requirements for the system and each Reserve Zone using a mathematical programming algorithm. The objective of the mathematical programming based Forward Reserve Auction clearing is to minimize the total cost of Forward Reserve procured to meet the Forward Reserve requirements. The Forward Reserve Clearing Price for each Reserve Zone will reflect the cost to serve the next increment of reserve in that Reserve Zone based on the submitted offers. The Forward Reserve Auction algorithm substitutes higher quality TMNSR for lower quality TMOR to meet system or Reserve Zone Forward Reserve requirements when it is economical to do so provided that no constraints are violated.

The Forward Reserve Auction algorithm shall also utilize excess Forward Reserve in one Reserve Zone to meet the Forward Reserve requirements of another Reserve Zone or the system provided that the Forward Reserve can be delivered such that no constraints are violated. In addition, the Forward Reserve Auction shall apply price cascading such that the Forward Reserve Clearing Price for TMOR in a Reserve Zone is always less than or equal to the Forward Reserve Clearing Price for TMNSR in that Reserve Zone. If there is insufficient supply to meet the Forward Reserve requirements for a Reserve Zone, the Forward Reserve Clearing Price for that Reserve Zone will be set to the Forward Reserve Offer Cap.

III.9.4.1 Forward Reserve Clearing Price and Forward Reserve Obligation Publication and Correction.

Market Participants with cleared Forward Reserve Auction Offers will receive a Forward Reserve Obligation for each Reserve Zone, as applicable, that is equal to the amount of Forward Reserve megawatts cleared for that Market Participant adjusted for internal bilateral transactions that transfer Forward Reserve Obligations.

(a) Within five business days after the close of the Forward Reserve Auctions, the ISO shall post Forward Reserve Clearing Prices and Forward Reserve Obligations, which shall be final as posted, not subject to correction or other adjustment, and used for the purposes of settlement, except as provided in subsections (c) and (d). The permissibility of correction of errors in sections of Market Rule 1 relating to settlement and billing processes shall not apply to Forward Reserve Clearing Prices and Forward Reserve Obligations deemed final pursuant to this Section III.9.4.1.

(b) Before posting the final Forward Reserve Clearing Prices and Forward Reserve Obligations, the ISO shall make a good faith effort when clearing those markets to discover and correct any errors that may occur due to database, software or similar errors of the ISO or its systems before publishing the final prices awarded.

(c) If the ISO determines based on reasonable belief that there may be one or more errors in the final Forward Reserve Clearing Prices and Forward Reserve Obligations or if no Forward Reserve Clearing Prices and Forward Reserve Obligations 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 11:59 p.m. of the third business day following the posting deadline specified in subsection (a), a notice that the Forward Reserve Clearing Prices and Forward Reserve Obligations are provisional and subject to correction or unavailable for initial publishing. The ISO shall confirm within three business days of posting a notice pursuant to this subsection whether there was an error in the Forward Reserve Clearing Prices and Forward Reserve Obligations and shall post a notice stating its findings.

(d) Within three business days after posting an initial notice pursuant to subsection (c); the ISO shall either: (1) publish final or corrected Forward Reserve Clearing Prices and Forward Reserve Obligations, or: (2) in the event that the ISO is unable to calculate and post final or corrected Forward Reserve Clearing Prices and Forward Reserve Obligations due to exigent circumstances not contemplated in this market rule, make an emergency filing with the Commission detailing the exigent circumstance which will not allow final Forward Reserve Clearing Prices and Forward Reserve Obligations to be calculated and posted, along with a proposed resolution including a timeline to post final prices.

III.9.5 Forward Reserve Resources

III.9.5.1 Assignment of Forward Reserve MWs to Forward Reserve Resources.

(a) Prior to the close of the Re-Offer Period for each Operating Day of the Forward Reserve Procurement Period, Market Participants must convert their Forward Reserve Obligations into Resource-specific obligations by assigning Forward Reserve MWs to specific eligible Forward Reserve Resources, in accordance with procedures set forth in the ISO New England Manuals. The assignment of Forward Reserve MWs to a Forward Reserve Resource must be performed by the Lead Market Participant for the Resource.

(b) A Market Participant with a Forward Reserve Obligation must have an Ownership Share in a Forward Reserve Resource that is a Generator Asset or a Dispatchable Asset Related Demand, or be the Lead Market Participant of a Forward Reserve Resource that is a Demand Response Resource, in order to assign Forward Reserve MWs to that Forward Reserve Resource to fulfill that Market Participant's Forward Reserve Obligation. If more than one Market Participant has an Ownership Share in a Forward Reserve Resource, the Forward Reserve MWs assigned to that Resource will be allocated pro-rata to Market Participants by Ownership Share.

III.9.5.2 Forward Reserve Resource Eligibility Requirements.

(a) Forward Reserve Resources are Resources that have been assigned by Market Participants to meet their Forward Reserve Obligations. To be eligible as a Forward Reserve Resource, a Resource must satisfy the following criteria:

(i) If the Generator Asset is off-line, it must be a Fast Start Generator and have an audited CLAIM10 or CLAIM30 established pursuant to Section III.9.5.3;

(ii) If the Resource is a Demand Response Resource which has not been dispatched, it must be a Fast Start Demand Response Resource and have an audited CLAIM10 or CLAIM30 established pursuant to Section III.9.5.3;

(iii) If the Generator Asset or Dispatchable Asset Related Demand is expected to be on-line, or, for a Demand Response Resource, has been dispatched, during a Forward Reserve Delivery Period, it must be able to produce the energy or demand reduction equivalent to its assigned Forward Reserve Obligation within the timeframe of the assigned Forward Reserve Obligation when operating within its dispatch range;

(iv) Any portion of the Resource to which a Forward Reserve Obligation has been assigned that is without a Capacity Supply Obligation must not have been offered to support an External Transaction sale during the Operating Day for which it has been assigned;

(v) The Resource must be capable of receiving and responding to electronic Dispatch Instructions;

(vi) The Resource must follow Dispatch Instructions during the Operating Day. The Resource must meet the technical requirements associated with the provision of Operating Reserve as specified in ISO New England Operating Procedure No. 14;

(vii) The portion of the Resource that is assigned a Forward Reserve Obligation for any portion of an Operating Day must be eligible to provide Operating Reserve in accordance with the provisions of Section III.1.7.19;

(viii) The portion of the Resource to which a Forward Reserve Obligation has been assigned must be offered into the Real-Time Energy Market in accordance with the provisions of either Section III.13.6.1.1.2 or Section III.13.6.1.5.2.

(b) External Resources will be permitted to participate in the Forward Reserve Market when the respective Control Areas implement the technology and processes necessary to support recognition of Operating Reserves from external Resources.

III.9.5.3 Resource CLAIM10 and CLAIM30.

III.9.5.3.1 Calculating Resource CLAIM10 and CLAIM30.

1. The CLAIM10 or CLAIM30 of a Resource shall equal:

   (a) the maximum output or demand-reduction level reached, including the level reached during a CLAIM10 or CLAIM30 audit, measured at the 10 minute or 30 minute point from the Resource's receipt of an initial electronic startup Dispatch Instruction during the current ~~Forward Reserve Procurement Period~~ Summer Capability Period or Winter Capability Period or the preceding ~~like-season Forward Reserve Procurement Period~~ Summer Capability Period or Winter Capability Period (as applicable to the current capability period), subject to the conditions in Section III.9.5.3.1.2 below;

   (b) multiplied by the Resource's then effective CLAIM10 or CLAIM30 performance factor established pursuant to Section III.9.5.3.3.

2. The value in Section III.9.5.3.1.1(a) is subject to the following additional conditions:

   (a) The value shall not include any dispatch in which the Resource becomes unavailable within 60 minutes following the receipt of the initial Dispatch Instruction;

   (b) If the maximum output or demand-reduction level reached, as measured at the 10 minute or 30 minute point from the initial Dispatch Instruction, is greater than the highest Desired Dispatch Point issued for the Resource for that 10 minute or 30 minute period, the value shall be capped at the highest Desired Dispatch Point.

3. A Resource's CLAIM10 shall be no greater than the Resource's CLAIM30.

4. The CLAIM10 or CLAIM30 of a Resource shall be calculated and distributed to the Market Participant weekly and shall become effective at 0001 of the Monday following the distribution.

5. The values described in Sections III.9.5.3.1(1)(a) and (b) shall not include any dispatch where:

   a) The Resource is dispatched at the request of the Market Participant or Designated Entity and the dispatch was not related to an Establish Claimed Capability Audit request made pursuant to Section III.1.5.1.2, a Seasonal DR Audit request made pursuant to Section III.1.5.1.3.1, or a CLAIM10 or CLAIM30 audit request made pursuant to Section III.9.5.3.2;

b) The prices associated with the Blocks to Economic Min for the Real-Time dispatch of the Resource are less than or equal to zero;

c) For Generator Assets, the ratio of (i) the sum of the applicable Start-Up Fee, No-Load Fee for one hour, and energy cost to Economic Min used in the Real-Time dispatch of the Resource in the Operating Day to (ii) the maximum total hourly Start-Up Fee, No-Load Fee for one hour, and energy cost to Economic Min submitted for the Resource for use in the Day-Ahead Energy Market for the same Operating Day, is below a threshold value determined by the ISO. If the Market Participant believes that the ratio is below the ISO-determined threshold value due to (i) differences in cost between Gas Days, or (ii) a reduction in the cost of gas within the Operating Day reflected in the offers submitted for the Resource during the remainder of the Operating Day, then the Market Participant may request that the ISO evaluate whether the dispatch may be included; or

d) For Demand Response Resources, the ratio of (i) the sum of the applicable Interruption Cost and the demand reduction cost to Minimum Reduction used in the Real-Time dispatch of the Demand Response Resource in the Operating Day to (ii) the maximum total hourly Interruption Cost and demand reduction cost to Minimum Reduction submitted for the Demand Response Resource for use in the Day-Ahead Energy Market for the same Operating Day, is below a threshold determined by the ISO. If the Market Participant believes that the ratio is below the ISO-determined threshold value due to differences in cost between Gas Days, then the Market Participant may request that the ISO evaluate whether the dispatch may be included.

6. A Demand Response Resource's CLAIM10 and CLAIM30 on June 1, 2018 and October 1, 2018 shall be as follows:

a) On June 1, 2018 and October 1, 2018, the CLAIM10 of a Demand Response Resource shall equal zero.

b) On June 1, 2018, the CLAIM30 of a Demand Response Resource with one or more Demand Response Assets that were 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) shall equal the sum of the 30 minute capabilities demonstrated by each such Demand Response Asset in a valid audit conducted during the Summer Capability Period beginning June 1, 2017. Such a CLAIM30 shall remain valid until the earlier of: (i) July 2, 2018, or (ii) receipt by the Demand Response Resource of an electronic startup Dispatch Instruction that permits the calculation of a CLAIM30 pursuant to Section III.9.5.3.1(1). If the Demand Response Resource does not receive such an electronic startup Dispatch Instruction on or before June 27, 2018, its CLAIM30 shall be set to zero on July 2, 2018.

c) On October 1, 2018, the CLAIM30 of a Demand Response Resource with one or more Demand Response Assets that were 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) shall equal the sum of the 30 minute capabilities demonstrated by each such Demand Response Asset in a valid audit conducted during the Winter Capability Period beginning October 1, 2017. Such a CLAIM30 shall remain valid until the earlier of: (i) October 29, 2018, or (ii) receipt by the Demand Response Resource of an electronic startup Dispatch Instruction that permits the calculation of a CLAIM30 pursuant to Section III.9.5.3.1(1). If the Demand Response Resource does not receive such an electronic startup Dispatch Instruction on or before October 24, 2018, its CLAIM30 shall be set to zero on October 29, 2018.

III.9.5.3.2 CLAIM10 and CLAIM30 Audits.

(a) **General.** A Market Participant may request a CLAIM10 or CLAIM30 audit specifying the requested output or demand-reduction level that the Resource will attempt to reach in 10 or 30 minutes. A Market Participant may not request more than one audit per week for the same Resource, provided that, if the Resource fails to start, trips offline, or becomes unavailable to provide a demand reduction during the audit, then the Market Participant may request another audit in the same week. The ISO, at its sole discretion, may allow a Market Participant to request more than one audit per week for the same Resource if the Resource historically has multiple startup dispatches included in its CLAIM10 or CLAIM30 calculations per week. A Market Participant may cancel an audit request prior to issuance of the audit Dispatch Instruction.

(b) **CLAIM10 and CLAIM30 Audit Procedures.** The ISO will initiate a CLAIM10 or CLAIM30 audit by issuing an electronic Dispatch Instruction without providing prior notice to the Market Participant. The ISO will normally perform the audit, at any time ~~during the Forward Reserve Delivery Period~~between 0800 and 2200 on a non-NERC-holiday weekday, within five Business Days of receipt of the audit request or will advise the Market Participant if it will be unable to initiate the audit during the five Business Day period. The Resource's CLAIM10 or CLAIM30 audit value shall be the Resource's output or demand-reduction level reached at the 10 minute or 30 minute point after the receipt of the initial startup Dispatch Instruction.

III.9.5.3.3 CLAIM10 and CLAIM30 Performance Factors.

A Resource's CLAIM10 or CLAIM30 performance factor shall be established based upon the 10 most recent ISO-issued initial electronic startup Dispatch Instructions as described below. Dispatches greater than three years old shall not be used for the performance factor calculation. Resource performance factors will be calculated on a weekly basis.

(a) A Resource's performance factor is calculated as:

$$\textit{performance factor} = \frac{\sum_{n=1}^{10}\left(\frac{\textit{resource output or demand reduction at 10 or 30 minutes}_n\ (MW)}{\textit{resource target value}_n\ (MW)} * n\right)}{\sum_{n=1}^{10} n}$$

Where:

n is a value between 1 and 10, 1 representing the least recent dispatch signal, 10 representing the most recent dispatch signal;

the Resource output or demand reduction is measured at the 10 minute or 30 minute point from receipt of the initial startup Dispatch Instruction;

the Resource target value is the lesser of: (i) the minimum electronic Desired Dispatch Point sent to the Resource during the 10 minute or 30 minute period or the Resource's Economic Minimum Limit or Minimum Reduction, whichever is greater or (ii) the Resource's CLAIM10 or CLAIM30 or (iii) the Resource's Offered CLAIM10 or Offered CLAIM30.

(b) For purposes of the performance factor calculation, the following conditions apply:

(i) For each CLAIM10 or CLAIM30 audit, the Resource's target value shall be set to the Resource's output or demand reduction at 10 or 30 minutes.

(ii) In the event the Resource has not had 10 electronic startup dispatches within the last three years, the "n" term in the performance factor calculation will be based on the number of startup dispatches that took place in the last three years, with the most recent dispatch having a weight of 10 and with the weighting decreasing by 1 for each previous startup dispatch.

(iii) If a Resource's output or demand reduction at 10 or 30 minutes is greater than the Resource's target value, then the Resource target value shall be set to the Resource output at 10 or 30 minutes.

(iv) A dispatch shall not be utilized in the performance factor calculation if a Resource starts and subsequently performs a normal shut down or ceases its demand reduction, in response to a Dispatch Instruction to shut down or, for a Demand Response Resource, in response to a Dispatch Instruction to cease its demand reduction, within the 10 or 30 minute period following the initial electronic startup Dispatch Instruction.

(v) Resource output or demand reduction at 10 or 30 minutes shall equal zero if the Resource becomes unavailable for dispatch within the 60 minute period following the initial electronic startup Dispatch Instruction.

III.9.5.3.4 Performance Factor Cure.

In the event a Resource either (a) is unable to reach at least 60% of the Resource target level, as reflected in the Dispatch Instruction issued for the Resource, either five times in a row or seven out of 10 times, as a result of a chronic operational problem with the Resource or (b) undergoes a major overhaul scheduled and performed during a planned outage that was approved in the ISO's annual maintenance scheduling process or during a scheduled curtailment pursuant to Section III.8.3, a Market Participant may submit a restoration plan to the ISO to restore the Resource's CLAIM10 or CLAIM30 operational capability. Restoration plans submitted because of a Resource's inability to reach its target output or demand reduction shall indicate the specific nature of the problem, the steps to be taken to remedy the problem, and the timeline for completing the restoration. Restoration plans submitted for a major overhaul shall explain the actions taken during the planned outage or scheduled curtailment that would result in the increase of the Resource's CLAIM10 or CLAIM30. The ISO shall accept restoration plans that, upon review, indicate a reasonable likelihood of success in remedying the identified problem or, for a major overhaul, increasing the Resource's CLAIM10 or CLAIM30. Upon completion of the restoration, the Market Participant shall request a CLAIM10 or CLAIM30 audit of the Resource, using the procedures in Section III.9.5.3.2. Following the audit, the Resource's Performance Factor shall be set to 1.0, with all dispatches prior to the audit removed from the performance factor calculation.

III.9.6 Delivery of Reserve.

III.9.6.1 Dispatch and Energy Bidding of Reserve.

Forward Reserve shall be delivered by Forward Reserve Resources that are Generator Assets or Dispatchable Asset Related Demand for an hour by offering the capability into the Real-Time Energy Market by submitting Supply Offers and Demand Bids no later than 30 minutes prior to the start of the operating hour at or above the Forward Reserve Threshold Price for the Operating Day. Day-Ahead Energy Market Supply Offers and Demand Bids for Resources to which Forward Reserve Obligations have been assigned will be used in the Real-Time Energy Market for the associated Operating Day, even if the Supply Offers do not clear the Day-Ahead Energy Market, unless superseded by a more recent Supply Offer or Demand Bid submitted no later than 30 minutes prior to the start of the operating hour. A Market Participant is not required to submit a Supply Offer or Demand Bid into the Day-Ahead Energy Market for a Resource without a Capacity Supply Obligation in order for the Resource to be eligible to be a Forward Reserve Resource. The Forward Reserve Threshold Prices shall be set in accordance with the ISO New England Manuals so that Forward Reserve Resource capability has (a) a low probability of being dispatched for energy and (b) a high probability of being held for reserve purposes.

Forward Reserve shall be delivered by Forward Reserve Resources that are Demand Response Resources for an hour by offering the capability into the Real-Time Energy Market by submitting Demand Reduction Offers no later than the close of the Re-Offer Period at or above the Forward Reserve Threshold Price for the Operating Day.

Forward Reserve Resources are scheduled and operated in accordance with Section III.1 of Market Rule 1; no distinction is made due to their status as Forward Reserve Resources. Forward Reserve Resources are eligible to set the Locational Marginal Price in accordance with Section III.2 of Market Rule 1.

III.9.6.2 Forward Reserve Threshold Prices.

The formula for determining the Forward Reserve Threshold Prices shall be fixed for the duration of the Forward Reserve Procurement Period. The ISO will reevaluate the Forward Reserve Threshold Price level for successive Forward Reserve Auctions on the basis of experience, expected operating conditions and other relevant information.

Forward Reserve Threshold Price: is calculated as the Forward Reserve Heat Rate multiplied by the daily Forward Reserve Fuel Index.

<u>Forward Reserve Heat Rate</u>: shall be fixed for the duration of the Forward Reserve Procurement Period and announced in the announcement for the Forward Reserve Auction. New Forward Reserve Heat Rates shall be specified for successive auctions, and shall be calculated as follows:

(a) For each of the five most recently completed Summer Capability Periods or Winter Capability Periods (as applicable to the Forward Reserve Procurement Period), for each on-peak hour, the ISO shall calculate an implied heat rate, expressed in Btu/kWh, by dividing the hour's Hub Price by the lower of the applicable natural gas or heating oil price index.

(b) All resulting hourly implied heat rates above 45,000 Btu/kWh shall be excluded, and the remaining values shall be listed in order from high to low.

(c) The Forward Reserve Heat Rate for the Forward Reserve Procurement Period shall be the lesser of: (i) the heat rate that occurs at the 97.5th percentile of the list described in subsection (b) above; or (ii) 21,999 Btu/kWh.

<u>Forward Reserve Fuel Index:</u> is a daily fuel index, or combination of daily indices, applicable to the New England Control Area and specified in the announcement of the Forward Reserve Auction.

III.9.6.3 Monitoring of Forward Reserve Resources.

In accordance with Section III.A.13.4, 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 Participant in accordance with Section III.A.3. 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.

III.9.6.4 Forward Reserve Qualifying Megawatts.

(a) **<u>Generator Assets and Dispatchable Asset Related Demands</u>** – Qualifying megawatts for Generator Assets and Dispatchable Asset Related Demands are calculated separately on an hourly basis for Forward Reserve Resources supplying Forward Reserve from an off-line state and Forward Reserve Resources supplying Forward Reserve from an on-line state as follows:

Off-line qualifying megawatts. Off-line qualifying megawatts are the amount of a Generator Asset's capability equal to or below the Economic Maximum Limit for an off-line Forward Reserve Resource offered at or above the Forward Reserve Threshold Price. The Generator Asset must satisfy this requirement in the Real-Time Energy Market. In the case of off-line Forward Reserve Resources, the calculation for Forward Reserve Qualifying Megawatts shall include both the energy Supply Offer and a pro-rated amount of Start-Up Fees and No-Load Fees as defined below. The off-line qualifying megawatts of a Dispatchable Asset Related Demand are zero.

An off-line Forward Reserve Resource must offer its capability so that the following holds:

$$\frac{StartUp}{EcoMax \times 1\ hour} + \frac{NoLoad}{EcoMax} + Energy\ Offer_{i} \geq ForwardReserveThresholdPrice$$

where:

StartUp = cold Start-Up Fee.

NoLoad = No-Load Fee.

$EnergyOffer_i$ = the Energy offer price for Energy offer block $_i$.

EcoMax = Economic Maximum Limit.

On-line qualifying megawatts: is the capability that is less than or equal to the Economic Maximum Limit and above the Economic Minimum Limit that is offered at or above the applicable Forward Reserve Threshold Price by an on-line Generator Asset or, is the capability that is less than or equal to the Maximum Consumption Limit and greater than the Minimum Consumption Limit offered at or above the applicable Forward Reserve Threshold Price for a Dispatchable Asset Related Demand. The Forward Reserve Resource must satisfy this requirement in the Real-Time Energy Market. For an on-line Generator Asset that has been assigned to meet a Forward Reserve Obligation and has not cleared in the Day-Ahead Energy Market and is operating in a delivery hour as the result of an ISO commitment for VAR or local second contingency protection, the on-line qualifying megawatts shall be zero.

(b) **Demand Response Resources** – Qualifying megawatts for Demand Response Resources supplying Forward Reserve are calculated separately on an hourly basis for Demand Response Resources that have not been dispatched and Demand Response Resources that have been dispatched as follows:

Qualifying megawatts for a Demand Response Resource that has not been dispatched: is the amount of capability equal to or below the Maximum Reduction for the Demand Response Resource offered at or above the Forward Reserve Threshold Price. The Demand Response Resource must satisfy this requirement in the Real-Time Energy Market. In the case of Demand Response Resources that have not been dispatched, the calculation for Forward Reserve Qualifying Megawatts shall include both the Demand Reduction Offer price and a pro-rated amount of the Interruption Cost as defined below.

A Demand Response Resource that has not been dispatched must offer its capability so that the following holds:

–

where:

Interruption Cost = Interruption Cost.

$EnergyOffer_i$ = Demand Reduction Offer price for Energy offer block $_i$.

Max Red = Maximum Reduction x 1 hour.

Qualifying megawatts for a Demand Response Resource which has been dispatched: is the capability that is less than or equal to the Maximum Reduction and greater than the Minimum Reduction that is offered at or above the applicable Forward Reserve Threshold Price for the Demand Response Resource. The Demand Response Resource must satisfy this requirement in the Real-Time Energy Market. For a Demand Response Resource which has been dispatched, has been assigned to meet a Forward Reserve Obligation, has not cleared in the Day-Ahead Energy Market, and is operating in a delivery hour as the result of an ISO commitment for local second contingency protection, the qualifying megawatts shall be zero.

III.9.6.5 Delivery Accounting.

Forward Reserve Delivered Megawatts are the quantity of Forward Reserve delivered in each hour of the Real-Time Energy Market to each Reserve Zone and is calculated as follows.

(a) <u>Forward Reserve Delivered Megawatts for an off-line Generator Asset</u> are calculated in megawatts for each hour of the Real-Time Energy Market for each Reserve Zone as the minimum of:

(i) the amount, in MW, of Forward Reserve that the off-line Generator Asset can provide, based upon CLAIM10 and CLAIM30 provided in the Generator Asset's Real-Time Supply Offer,

(ii) Forward Reserve Assigned Megawatts, or

(iii) Forward Reserve Qualifying Megawatts for that Resource (MW offered at or above the applicable Forward Reserve Threshold Price per Section III.9.6.2), less any previously accounted for Forward Reserve Delivered Megawatts for that Resource.

(b) Forward Reserve Delivered Megawatts for an on-line Generator Asset are calculated in megawatts for each hour for each Reserve Zone as the minimum of:

(i) 10 or 30 times the MW/minute ramp rate of the on-line Generator Asset, as applicable,

(ii) Forward Reserve Assigned Megawatts, or

(iii) Forward Reserve Qualifying Megawatts for that Resource (MW offered at or above the applicable Forward Reserve Threshold Price per Section III.9.6.2)

less any previously accounted for Forward Reserve Delivered Megawatts for that Resource.

(c) Forward Reserve Delivered Megawatts for an on-line Dispatchable Asset Related Demand are calculated for each hour of the Real-Time Energy Market for each Reserve Zone as the minimum of:

(i) 10 or 30 times the MW/minute ramp rate of the Resource, as applicable,

(ii) Forward Reserve Assigned Megawatts, or

(iii) Forward Reserve Qualifying Megawatts for that Resource (MW offered at or above the applicable Forward Reserve Threshold Price per Section III.9.6.2),

less any previously accounted for Forward Reserve Delivered Megawatts for that Resource.

(d) A Forward Reserve Resource's hourly Forward Reserve Delivered Megawatts for each Reserve Zone is calculated as the sum of the Market Participant's Resource specific hourly Forward Reserve Delivered Megawatts for each Reserve Zone.

(e) Resource specific Forward Reserve Delivered Megawatts for TMNSR within a Reserve Zone will be applied first to a Market Participant's higher value Forward Reserve Obligation for TMNSR in that Reserve Zone. Any surplus Forward Reserve Delivered Megawatts for TMNSR in that Reserve Zone will be applied to meet the Market Participant's Forward Reserve Obligation for TMOR in that Reserve Zone. Forward Reserve Delivered Megawatts remaining within that Reserve Zone after the Market Participant's Forward Reserve Obligation for that Reserve Zone have been met is available to be applied to the Market Participant's Forward Reserve Obligations in other Reserve Zones provided that the Forward Reserve Delivered Megawatts can be delivered to the other Reserve Zones.

(f) Forward Reserve Delivered Megawatts for a Demand Response Resource which has not been dispatched are calculated for each hour of the Real-Time Energy Market for each Reserve Zone as the minimum of:

(i) the amount of Forward Reserve that the Resource can provide, based upon CLAIM10 and CLAIM30 provided in the Demand Response Resource's Demand Reduction Offer,

(ii) Forward Reserve Assigned Megawatts, or

(iii) Forward Reserve Qualifying Megawatts for that Resource (energy at or above the applicable Forward Reserve Threshold Price per Section III.9.6.2), less any previously accounted for Forward Reserve Delivered Megawatts for that Resource.

(g) Forward Reserve Delivered Megawatts for a Demand Response Resource which has been dispatched are calculated for each hour for each Reserve Zone as the minimum of:

(i) 10 or 30 times the MW/minute Demand Response Resource Ramp Rate of that Resource, as applicable,

(ii) Forward Reserve Assigned Megawatts, or

(iii) Forward Reserve Qualifying Megawatts for that Resource (MW offered at or above the applicable Forward Reserve Threshold Price per Section III.9.6.2)

less any previously accounted for Forward Reserve Delivered Megawatts for that Resource.

(h) In determining Forward Reserve Delivered Megawatts for Demand Response Resources the portion of the Forward Reserve Delivered Megawatts not associated with Net Supply shall be increased by average avoided peak distribution losses, limited as described below.

(i) The ISO will assume that Demand Response Resources first reduce their net load from the electricity system before providing additional Net Supply.

(ii) The portion of the Forward Reserve Delivered Megawatts not associated with Net Supply shall be the lesser of: (1) Forward Reserve Delivered Megawatts and (2) the amount of load that the Demand Response Resource can reduce from the electric system based on the net load of its constituent Demand Response Assets.

(iii) Any remaining Forward Reserve Delivered Megawatts in excess of the portion not associated with Net Supply will be capped at the remaining Net Supply Capability of the Demand Response Resource.

III.9.7 Consequences of Delivery Failure.

III.9.7.1 Real-Time Failure-to-Reserve.

A Real-Time Forward Reserve Failure-to-Reserve 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.

(a) Forward Reserve Failure-to-Reserve Megawatts:

(i) A Market Participant's Forward Reserve Failure-to-Reserve Megawatts for TMNSR for a Reserve Zone is defined as, for each hour, the amount that is the maximum of the following values:

(1) Market Participant Forward Reserve Obligation for TMNSR for that Reserve Zone minus the Market Participant's Forward Reserve Delivered Megawatts for TMNSR for that Reserve Zone; and

(2) Zero.

(ii) A Market Participant's Forward Reserve Failure-to-Reserve Megawatts for TMOR for a Reserve Zone is defined as, for each hour, the amount that is the maximum of the following values:

(1) Market Participant Forward Reserve Obligation for TMOR for that Reserve Zone minus Market Participant's Forward Reserve Delivered Megawatts for TMOR for that Reserve Zone; and

(2) Zero.

(b) <u>Forward Reserve Failure-to-Reserve Penalties</u>: A Market Participant's Forward Reserve Failure-to-Reserve Penalty for a Reserve Zone in an hour is defined as:

(i) Forward Reserve Failure-to-Reserve Penalty for TMNSR = Forward Reserve Failure-to-Reserve Penalty Rate multiplied by the Forward Reserve Failure-to-Reserve Megawatts for TMNSR; and

(ii) Forward Reserve Failure-to-Reserve Penalty for TMOR = Forward Reserve Failure-to-Reserve Penalty Rate multiplied by the Forward Reserve Failure-to-Reserve Megawatts for TMOR;

Where:

Forward Reserve Failure-to-Reserve Penalty Rate (calculated for each Forward Reserve product and for each Reserve Zone) = maximum of (1.5 multiplied by the Forward Reserve Payment Rate for the Forward Reserve product, the applicable Real-Time Reserve Clearing Price for the Forward Reserve product in the Reserve Zone minus the Forward Reserve Payment Rate for the Forward Reserve product)

III.9.7.2 Failure-to-Activate Penalties.

Market Participants are required to pay a Forward Reserve Failure-to-Activate Penalty for each Forward Reserve Resource that fails to activate its Forward Reserve capability. For Forward Reserve Resources:

- providing TMNSR, the Forward Reserve Failure-to-Activate Penalty is applied if a resource fails to activate in response to a Dispatch Instruction as part of the real-time contingency dispatch algorithm, or;
- providing TMOR, the Forward Reserve Failure-to-Activate Penalty is applied if a resource fails to activate in response to a Dispatch Instruction when the ten-minute reserve requirement is binding or violated in an approved UDS case.

If a Market Participant's Forward Reserve Resource fails to activate Forward Reserve, which determination shall be made in accordance with subsection (a), that Market Participant shall be required to pay a Forward Reserve Failure-to-Activate Penalty associated with that Resource pursuant to subsection (b):

(a) **Forward Reserve Failure-to-Activate Megawatts**:

(i) A Market Participant's Forward Reserve Failure-to-Activate Megawatts for TMNSR for a Resource is defined as, for each hour, the amount that is the lesser of the following values:

(1) Maximum of Forward Reserve Delivered Megawatts for TMNSR minus actual amount of TMNSR energy delivered during activation, or zero;

(2) Maximum of Target Activation Megawatts for TMNSR minus actual amount of TMNSR energy delivered during activation, or zero;

Where:

Target Activation Megawatts for TMNSR from off-line Forward Reserve Resources or Demand Response Resources that are not dispatched, which are subsequently dispatched as part of the real-time contingency dispatch algorithm is the lesser of: (i) the minimum electronic Desired

Dispatch Point sent to the Resource during the 10 minute period or the Resource’s Economic Minimum Limit or Minimum Reduction, whichever is greater, (ii) the Resource’s CLAIM10, and (iii) the Resource’s Offered CLAIM10.

Target Activation Megawatts for TMNSR from on-line Forward Reserve Resources or Demand Response Resources that have been dispatched is as follows:

1. For Generator Assets, the lesser of: (i) the Resource’s Manual Response Rate times 10 minutes, (ii) the Resource’s Economic Maximum Limit minus the Resource’s initial output at activation, and (iii) the minimum electronic Desired Dispatch Point sent to the Resource during the 10 minute period minus the Resource’s initial output at activation.
2. For Storage DARDs, the Resource’s initial consumption at activation minus the maximum electronic Desired Dispatch Point sent to the Resource during the 10 minute period.
3. For DARDs that are not Storage DARDs, the lesser of: (i) the Resource’s Manual Response Rate times 10 minutes, (ii) Resource’s initial consumption at activation minus the Resource’s Minimum Consumption Limit, and (iii) the Resource’s initial consumption at activation minus the maximum electronic Desired Dispatch Point sent to the Resource during the 10 minute period.
4. For Demand Response Resources, the lesser of: (i) the Resource’s Demand Response Resource Ramp Rate times 10 minutes, (ii) the Resource’s Maximum Reduction minus the Resource’s initial demand reduction at activation, and (iii) the minimum electronic Desired Dispatch Point sent to the Resource during the 10 minute period minus the Resource’s initial demand reduction at activation.

The actual amount of TMNSR energy delivered during activation is measured at the 10 minute point following receipt of the initial Dispatch Instruction. The actual amount of TMNSR energy delivered during activation is set to zero if the Resource becomes unavailable for dispatch within the 60 minute period following the receipt of the initial Dispatch Instruction.

(ii) A Market Participant’s Forward Reserve Failure-to-Activate Megawatts for TMOR for a Resource is defined as, for each hour, the amount that is the lesser of the following values:

(1) Maximum of Forward Reserve Delivered Megawatts for TMOR plus Forward Reserve Delivered Megawatts for TMNSR minus Forward Reserve Failure-to-Activate Megawatts for TMNSR minus actual amount of TMOR energy delivered during activation, or zero;

(2) Maximum of Target Activation Megawatts for TMOR minus Forward Reserve Failure-to-Activate Megawatts for TMNSR minus actual amount of TMOR energy delivered during activation, or zero;

Where:

Target Activation Megawatts for TMOR from off-line Forward Reserve Resources or Demand Response Resources that are not dispatched is the lesser of: (i) the minimum electronic Desired Dispatch Point sent to the Resource during the 30 minute period or the Resource's Economic Minimum Limit or Minimum Reduction, whichever is greater or (ii) the Resource's CLAIM30, or; (iii) the Resource's Offered CLAIM30.

Target Activation Megawatts for TMOR from on-line Forward Reserve Resources or Demand Response Resources that have been dispatched is as follows:

1. For Generator Assets, the lesser of: (i) the Resource's Manual Response Rate times 30 minutes, (ii) the Resource's Economic Maximum Limit minus the Resource's initial output at activation, and (iii) the minimum electronic Desired Dispatch Point sent to the Resource during the 30 minute period minus the Resource's initial output at activation.
2. For Storage DARDs, the Resource's initial consumption at activation minus the maximum electronic Desired Dispatch Point sent to the Resource during the 30 minute period.
3. For DARDs that are not Storage DARDs, the lesser of: (i) the Resource's Manual Response Rate times 30 minutes, (ii) Resource's initial consumption at activation minus the Resource's Minimum Consumption Limit, and (iii) the Resource's initial consumption at activation minus the maximum electronic Desired Dispatch Point sent to the Resource during the 30 minute period.

4. For Demand Response Resources, the lesser of: (i) the Resource's Demand Response Resource Ramp Rate times 30 minutes, (ii) the Resource's Maximum Reduction minus the Resource's initial demand reduction at activation, and (iii) the minimum electronic Desired Dispatch Point sent to the Resource during the 30 minute period minus the Resource's initial demand reduction at activation.

The actual amount of TMOR energy delivered during activation is measured at the 30 minute point following receipt of the initial Dispatch Instruction. The actual amount of TMOR energy delivered during activation is set to zero if the Resource becomes unavailable for dispatch within the 60 minute period following the receipt of the initial Dispatch Instruction.

(iii) In determining the Target Activation Megawatts for Demand Response Resources, the portion of the Target Activation Megawatts not associated with Net Supply shall be increased by average avoided peak distribution losses. The portion of the Target Activation Megawatts not associated with Net Supply shall be calculated as the greater of: (1) the Target Activation Megawatts minus the amount of Net Supply that the Demand Response Resource produced during activation or (2) zero.

A Forward Reserve Resource that is a Fast Start Generator that fails to activate Forward Reserve through a failure to start, or a Forward Reserve Resource that is a Fast Start Demand Response Resource that fails to activate Forward Reserve through a failure to provide a demand reduction, shall have its Forward Reserve Delivered Megawatts set equal to zero in each subsequent hour in the applicable Forward Reserve Delivery Period until such time that the Market Participant notifies the ISO that the Forward Reserve Resource is capable of providing the Forward Reserve Delivered Megawatts.

(b) **Forward Reserve Failure-to-Activate Penalties:**

A Market Participant's Forward Reserve Failure-to-Activate Penalty for a Resource in an hour is defined as:

(i) Forward Reserve Failure-to-Activate Penalty for TMNSR = The sum of the Forward Reserve Payment Rate for TMNSR and the Forward Reserve Failure-to-Activate Penalty Rate multiplied by the Forward Reserve Failure-to-Activate Megawatts for TMNSR; and

(ii) Forward Reserve Failure-to-Activate Penalty for TMOR = The sum of the Forward Reserve Payment Rate for TMOR and the Forward Reserve Failure-to-Activate Penalty Rate multiplied by the Forward Reserve Failure-to-Activate Megawatts for TMOR;

Where:

Forward Reserve Failure-to-Activate Penalty Rate = Maximum of 2.25 multiplied by the Forward Reserve Payment Rate, or the applicable nodal LMP.

III.9.7.3 Known Performance Limitations.

The ISO may have reason to believe that a particular Forward Reserve Resource is frequently receiving, or may frequently receive, Forward Reserve payments for a portion or all of its capability that is not capable of activating the Forward Reserve Assigned Megawatts for TMNSR or the Forward Reserve Assigned Megawatts for TMOR. When the ISO believes there is such a limited Forward Reserve Resource, the ISO shall contact and confer with the affected Market Participant before taking any action.

(a) The ISO will, whenever practicable, contact the affected Market Participant of the Forward Reserve Resource to request an explanation of the relevant resource Offer Data;

(b) If the explanation, if available, considered together with other information available to the ISO, indicates to the satisfaction of the ISO that the questioned Forward Reserve payments are consistent with Forward Reserve Resource capabilities, no further action will be taken; and

(c) If no agreement is reached, or an acceptable explanation is not provided, the Market Participant may request a Resource performance audit. If the Forward Reserve Resource fails the performance audit or the Market Participant refuses to request a Resource performance audit, the ISO may take remedial action. Remedial actions may include, but are not limited to: (i) redeclaration, by the ISO, of any relevant operational Offer Data parameter, or (ii) removing the Resource or the relevant portion of the Resource's capability to provide Forward Reserve on a going-forward basis.

III.9.8 Forward Reserve Credits.

Payment for Forward Reserve is based upon a Market Participant's Final Forward Reserve Obligation and the applicable Forward Reserve Clearing Prices. The ISO shall calculate these credits on an hourly basis for each Reserve Zone as follows:

(a) Final Forward Reserve Obligations for TMNSR and TMOR for each Market Participant are calculated for each Reserve Zone for each hour as follows:

(i) Final Forward Reserve Obligation = minimum [Forward Reserve Obligation, Forward Reserve Delivered Megawatts]

(b) $FRACP_{Zone}$ is defined as the Forward Reserve Clearing Price for the relevant Reserve Zone, for TMNSR or TMOR, respectively;

(c) Market Participant Forward Reserve Credit for TMNSR=Final Forward Reserve Obligation for TMNSR multiplied by the applicable hourly Forward Reserve Payment Rate for TMNSR;

where,

the hourly Forward Reserve Payment Rate for TMNSR is equal to:

applicable monthly $FRACP_{Zone}$ for TMNSR divided by the number of hours in the month associated with the Forward Reserve Delivery Period.

(d) Market Participant Forward Reserve Credit for TMOR = Final Forward Reserve Obligation for TMOR multiplied by the applicable hourly Forward Reserve Payment Rate for TMOR;

where,

the hourly Forward Reserve Payment Rate for TMOR is equal to:

applicable monthly $FRACP_{Zone}$ for TMOR divided by the number of hours in the month associated with the Forward Reserve Delivery Period.

III.9.9 Forward Reserve Charges.

Forward Reserve Charges are allocated to each Market Participant in two steps. The first step allocates the Forward Reserve Credits associated with the procurement of reserves to meet the Forward Reserve requirement for the system. The second step, if necessary, allocates any remaining Forward Reserve Credits.

III.9.9.1 Forward Reserve Credits Associated with System Reserve Requirement.
The portion of Forward Reserve Credits associated with the procurement of the Forward Reserve requirement for the system is determined by simulating a Forward Reserve Auction using all submitted Forward Reserve Auction Offers to meet only the Forward Reserve Market minimum requirements for the New England Control Area pursuant to Section III.9.2.1. The simulated Forward Reserve Auction will clear offers pursuant to the methodology set forth in Section III.9.4 to calculate TMNSR and TMOR proxy system clearing prices. The TMNSR and TMOR proxy system clearing prices will reflect the cost to serve the next increment of reserve above the Forward Reserve Market minimum requirement for the New England Control Area.

For each hour, the total amount of Forward Reserve Credits associated with the procurement of the Forward Reserve requirement for the system is calculated as the lesser of:

(i) The TMNSR Forward Reserve Market minimum requirement for the New England Control Area pursuant to Section III.9.2.1 multiplied by the TMNSR proxy system clearing price, plus the TMOR Forward Reserve Market minimum requirement for the New England Control Area pursuant to Section III.9.2.1 multiplied by the TMOR proxy system clearing price and divided by the number of hours in the month associated with the Forward Reserve Delivery Period, or

(ii) Total Forward Reserve Credits for the New England Control Area as calculated pursuant to Section III.9.8.

III.9.9.2 Adjusting Forward Reserve Credits for System Requirement.
For each hour, the Forward Reserve Credits associated with the procurement of the Forward Reserve requirement for the system is reduced by:

(i) Any Forward Reserve Failure-to-Reserve Penalty or Forward Reserve Failure-to-Activate Penalty that occurs in the Rest of System or in a Load Zone that is ineligible to receive an allocation of Forward Reserve Credits pursuant to Section III.9.9.4.1, and

(ii) A prorated amount of any Forward Reserve Failure-to-Reserve Penalty or Forward Reserve Failure-to-Activate Penalty that occurs in a Load Zone that is eligible to receive an allocation of Forward Reserve Credits pursuant to Section III.9.9.4.1, where the prorated amount is calculated based on the ratio of Forward Reserve Credits calculated in Section III.9.9.1 to the total Forward Reserve Credits.

III.9.9.3 Allocating Forward Reserve Credits for System Requirements.

For each hour, the Forward Reserve Credits associated with the procurement of the Forward Reserve requirements for the system as calculated pursuant to Section III.9.9.1, is reduced by any penalties calculated pursuant to Section III.9.9.2, and allocated on a pro rata basis using each Market Participant's share of Real-Time Load Obligation in each Load Zone (which includes the Market Participant's Real-Time Load Obligation associated with any Capacity Export Through Import Constrained Zone Transaction pursuant to Section III.1.10.7(f)(i) or with any FCA Cleared Export Transaction pursuant to Section III.1.10.7(f)(ii), reduced by that Market Participant's Reserve Quantity For Settlement associated with Dispatchable Asset Related Demands within that Load Zone.

III.9.9.4 Allocating Remaining Forward Reserve Credits.

For each hour, any Forward Reserve Credits not allocated pursuant to Section III.9.9.3 are allocated on a pro rata basis to each Market Participant's share of Real-Time Load Obligation in a Load Zone (which includes the Market Participant's Real-Time Load Obligation associated with any Capacity Export Through Import Constrained Zone Transaction pursuant to Section III.1.10.7(f)(i) or with any FCA Cleared Export Transaction pursuant to Section III.1.10.7(f)(ii), reduced by that Market Participant's Reserve Quantity For Settlement associated with Dispatchable Asset Related Demands within that Load Zone) that meets the criteria in Section III.9.9.4.1. The allocation for each Load Zone is based on the ratio of the Forward Reserve Credits cleared in the Respective Reserve Zone for the Forward Reserve Credits cleared in all Reserve Zones that meet the criteria in Section III.9.9.4.1, and is reduced by:

(i) A prorated amount of any Forward Reserve Failure-to-Reserve Penalties or Forward Reserve Failure-to-Activate Penalties that occur in a Load Zone eligible to receive an allocation of Forward Reserve Credits pursuant to Section III.9.9.4.1, where the prorated amount is calculated based on the ratio of the total Forward Reserve Credits less any Forward Reserve Credits calculated in Section III.9.9.1 to the total Forward Reserve Credits.

III.9.9.4.1 Allocation Criteria for Remaining Forward Reserve Credits.

If the following criteria are met, then a Market Participant with Real-Time Load Obligation in a Load Zone is eligible to receive any remaining Forward Reserve Credits not allocated pursuant to Section III.9.9.3.

(i) The Load Zone is encompassed in whole or in part in a Reserve Zone with a zonal Forward Reserve requirement greater than zero, and

(ii) The Forward Reserve Clearing Price of a Reserve Zone is higher than the Forward Reserve Clearing Price of the Rest of System.

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 or Day-Ahead Ancillary Services Offer for a Resource that is unjustifiably high and violates the economic withholding criteria set forth in Section III.A.5 or Section III.A.8 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.8, 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 and Day-Ahead Ancillary Services Offers in accordance with Section III.A.4 below for referral to the Commission.

(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 referral under Section III.A.19.

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.8, III.A.10, and III.A.11 below.

III.A.2.4.3. Applicability.

Mitigation measures may be applied to Supply Offers, Increment Offers, Day-Ahead Ancillary Services 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***.

III.A.2.4.6. Correction of Mitigation.

If the Internal Market Monitor determines that there are one or more errors in the mitigation applied pursuant to Sections III.A.5 or III.A.8 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 Operating Day associated with the Supply Offer or Day-Ahead Ancillary Services Offer to which such mitigation applied. The ISO shall correct the error as part of the Data Reconciliation Process by applying the correct values to the relevant Supply Offer or Day-Ahead Ancillary Services 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.2.4.7. Delay of Day-Ahead Market Due to Mitigation Process.

The posting of the Day-Ahead Market results may be delayed if necessary for the completion of mitigation procedures.

III.A.3. Consultation Prior to Determination of Reference Levels for Physical and Financial Parameters of Resources and Benchmark Levels for Day-Ahead Ancillary Services Offers; 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 and Day-Ahead Ancillary Services Benchmark Levels under Section III.A.8.2 for that Market Participant**.** In order for the Internal Market Monitor to revise Reference Levels or Day-Ahead Ancillary Services Benchmark Levels, or treat an offer as not violating applicable conduct tests specified in Section III.A.5.5 or Section III.A.8.1.1 for an Operating Day or hour for which the offer is submitted, all cost data and other verifiable supporting 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 or Day-Ahead Ancillary Services Benchmark 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.

(a) 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(c~~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 related to a Supply Offer, the Internal Market Monitor will either update the Reference Level or treat ~~an~~ the 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.~~

(b) 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(c), believes will cause the expected close-out costs or input costs associated with a Day-Ahead Ancillary Services Offer to exceed the level that would violate the conduct test specified in Section III.A.8.1.1 of this ***Appendix A***, the Market Participant may contact the Internal Market Monitor to provide an explanation of the increased costs. If the Internal Market Monitor determines that there is an increased cost related to a Day-Ahead Ancillary Services Offer, the Internal Market Monitor will either update one or both of the components of the Day-Ahead Ancillary Services Benchmark Level, as applicable, or treat the offer as not violating the conduct test specified in Section III.A.8.1.1 for the hour for which the offer is submitted.

(c) 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.~~

~~(a)~~(d) Any request pursuant to this Section III.A.3.1 must be submitted to the Internal Market Monitor with all supporting cost data and other verifiable supporting information. In order for a request pursuant to this Section III.A.3.1 to be considered for the purposes of the Day-Ahead Market, the Market Participant must contact the Internal Market Monitor at least 30 minutes prior to the close of the Day-Ahead Market. In order for a request 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. A request 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.

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 and Day-Ahead Ancillary Services Benchmark Levels.

The Internal Market Monitor will make available to the Market Participant the Reference Levels and both components of the Day-Ahead Ancillary Services Benchmark Levels applicable to that Market Participant's Supply Offers and any Day-Ahead Ancillary Services Offers through the MUI. Updated Reference Levels and components of the Day-Ahead Ancillary Services Benchmark Levels will be made available whenever calculated. The Market Participant shall not modify such Reference Levels or the components of the Day-Ahead Ancillary Services Benchmark 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 and the Day-Ahead Ancillary Services Avoidable Input Cost for any associated Day-Ahead Ancillary Services Offers, 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 and the Day-Ahead Ancillary Services Avoidable Input Cost for any associated Day-Ahead Ancillary Services Offers. 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, and for any associated Day-Ahead Ancillary Services Offers entered in the Day-Ahead Ancillary Services Market. 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 and the Day-Ahead Ancillary Services Avoidable Input Cost for any associated Day-Ahead Ancillary Services Offers, the fuel price must be submitted prior to the applicable ~~Supply O~~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 and to cover an award consistent with any associated Day-Ahead Ancillary Services Offers, exclusive of resource-specific transportation costs. Modifications to Reference Levels or Day-Ahead Ancillary Services Avoidable Input Costs 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 and any Day-Ahead Ancillary Services Avoidable Input Cost or (2) the fuel price used by the Internal Market Monitor in calculating the Reference Levels for the Resource's Supply Offer and any Day-Ahead Ancillary Services Avoidable Input Cost 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 and any associated Day-Ahead

Ancillary Services Offers, as of the time that the Supply Offer and any associated Day-Ahead Ancillary Services Offers were~~as~~ 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 and the components of Day-Ahead Ancillary Services Benchmark 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 Day-Ahead Ancillary Services 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) As applied to the Day-Ahead Ancillary Services Market, withholding that exceeds the greater of 20% or 100 MW of the total Day-Ahead Ancillary Services capability of a Market Participant's Resources; or

(d) 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 and Day-Ahead Ancillary Services capability 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 Sections III.A.5 or III.A.8, as appropriate.

III.A.5. Supply Offer 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. Supply Offer 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. Day-Ahead Ancillary Services Offer Mitigation.~~[Reserved.]~~

Day-Ahead Ancillary Services Offers will be evaluated for economic withholding in the Day-Ahead Market and mitigated as described in this Section III.A.8.

III.A.8.1. Conduct and Impact Test.

III.A.8.1.1. Conduct Test.

A Day-Ahead Ancillary Services Offer price fails the conduct test for Day-Ahead Ancillary Services Offer mitigation in a given hour if such price exceeds an amount greater than the sum of (i) the greater of $2/MWh and 200% of the Day-Ahead Ancillary Services Expected Close-Out Component as described in Section III.A.8.2.1; and (ii) 150% of the Day-Ahead Ancillary Services Avoidable Input Cost as described in Section III.A.8.2.2.

III.A.8.1.2. Impact Test.

A Day-Ahead Ancillary Services Offer with a price that fails the conduct test for Day-Ahead Ancillary Services Offer mitigation shall be evaluated against the impact test for Day-Ahead Ancillary Services Offer mitigation. A Day-Ahead Ancillary Services Offer fails the impact test for Day-Ahead Ancillary Services Offer mitigation if there is an increase in any Day-Ahead Price, as calculated pursuant to Sections III.A.8.3 or III.A.8.4, in any hour of the Operating Day and such increase is greater than 150% of the median difference between:

(i) the threshold prices for failing the conduct test described in Section III.A.8.1.1 for all Day-Ahead Ancillary Services Offers in the hour of the Operating Day being evaluated; and

(ii) the Day-Ahead Ancillary Services Benchmark Levels as described in Section III.A.8.2 for all Day-Ahead Ancillary Services Offers in the hour of the Operating Day being evaluated.

III.A.8.1.3. Consequence of Failing Both Conduct and Impact Test.

If any Day-Ahead Ancillary Services Offer with a price that fails the Day-Ahead Ancillary Services Offer conduct test fails the impact test, then all Day-Ahead Ancillary Services Offer prices that failed the conduct test in the hour being evaluated shall be set to the applicable Day-Ahead Ancillary Services Benchmark Level.

III.A.8.2. Day-Ahead Ancillary Services Benchmark Levels.

A resource's Day-Ahead Ancillary Services Benchmark Level for the hour associated with the resource's Day-Ahead Ancillary Services Offer is the sum of the Day-Ahead Ancillary Services Expected Close-Out Component and the resource's Day-Ahead Ancillary Services Avoidable Input Cost for such hour.

III.A.8.2.1. Day-Ahead Ancillary Services Expected Close-Out Component.

The Day-Ahead Ancillary Services Expected Close-Out Component for a given hour is the lesser of the following:

(a) the expected value of the greater of (i) the hourly Real-Time Hub Price less the hourly Day-Ahead Ancillary Services Strike Price and (ii) zero; and

(b) the historical average of the estimated likelihood that the Real-Time Hub Price will be equal to or less than its expected value, multiplied by the greater of $100/MWh and the expected hourly Real-Time Hub Price.

III.A.8.2.2. Day-Ahead Ancillary Services Avoidable Input Cost.

For purposes of calculating Day-Ahead Ancillary Services Benchmark Levels and conducting the conduct test described in Section III.A.8.1.1, Day-Ahead Ancillary Services Avoidable Input Costs shall be determined as follows:

(a) For a Generator Asset with natural gas as its only fuel type, or a dual-fuel Generator Asset that has specified natural gas as its fuel type in its Supply Offer for the hour associated with the Day-Ahead Ancillary Services Offer, the Day-Ahead Ancillary Services Avoidable Input Cost shall be calculated based on the asset's average heat rate and the expected price of natural gas to cover the Day-Ahead Ancillary Services award, adjusted for the expected hourly Real-Time Hub Price.

(b) For an asset that is an Electric Storage Facility, the Day-Ahead Ancillary Services Avoidable Input Cost shall be calculated based on the expected cost of charging energy to cover the Day-Ahead Ancillary Services award, adjusted for the expected Real-Time revenue associated with that charged energy during the Operating Day.

(c) For asset types other than those described in subsections (a) and (b), the Day-Ahead Ancillary Services Avoidable Input Cost shall be zero.

(d) The Day-Ahead Ancillary Services Avoidable Input Cost shall in no case be less than zero.

III.A.8.2.3. Cost Information Provided Through Consultation.

In performing the Day-Ahead Ancillary Services Benchmark Level calculations in this Section III.A.8.2, the Internal Market Monitor shall take into account, as appropriate, information provided by the Market Participant through the consultation process described in Section III.A.3. The criteria enumerated in (a) through (e) of Section III.A.7.5 shall apply to estimates of costs when performing Day-Ahead Ancillary Services Benchmark Level calculations.

III.A.8.3. Calculation of Impact to the Day-Ahead Ancillary Services Market.

For the purpose of determining any increase in Day-Ahead Ancillary Services prices pursuant to Section III.A.8.1.2, the Day-Ahead Ancillary Service impact test shall calculate the difference between two Day-Ahead Ancillary Service prices for each product in each hour. The first price shall be calculated based on a run of the Day-Ahead Market using all Day-Ahead offers and bids as submitted. The second price shall be calculated based on a second run of the Day-Ahead Market substituting Day-Ahead Ancillary Services Benchmark Levels for the Day-Ahead Ancillary Services Offer prices that have failed the Day-Ahead Ancillary Services conduct test.

III.A.8.4. Calculation of Impact to the Day-Ahead Energy Market.

For the purpose of determining any increase in Day-Ahead energy prices pursuant to Section III.A.8.1.2, the Day-Ahead Ancillary Service impact test shall calculate the difference between two prices in each hour. The first price shall be the Hub Price calculated based on a run of the Day-Ahead Market using all Day-Ahead offers and bids as submitted. The second price shall be the Hub Price calculated based on a second run of the Day-Ahead Market substituting Day-Ahead Ancillary Services Benchmark Levels for the Day-Ahead Ancillary Services Offer prices that have failed the Day-Ahead Ancillary Services conduct test.

III.A.8.5. Duration of Day-Ahead Ancillary Services Offer Mitigation.

Any mitigation imposed on a Day-Ahead Ancillary Services Offer pursuant to this Section III.A.8 is in effect only for the hour in which the Day-Ahead Ancillary Services Offer has a price that fails the conduct test in Section III.A.8.1.1.

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.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.

(i) 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, or Day-Ahead Ancillary Services close-out or input 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(i)(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(i)(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.

(ii) 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 Market Participant also may submit a filing under Section III.A.15.2(i)(a) to seek recovery of opportunity costs within the Day-Ahead Market as a result of mitigation applied to the Resource's Day-Ahead Ancillary Services Offer under Section III.A.8. To recover such opportunity costs, the Market Participant must demonstrate as part of the filing requirements of Section III.A.15.2.1(iii) and (iv) that the original, unmitigated Day-Ahead Ancillary Services Offer reflected costs anticipated by the Market Participant at the time the offer was made. The filing must be made within the time period specified for a filing to address cost recovery under Section III.A.15.2(i)(a).

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, or Day-Ahead Ancillary Services close-out or input costs, or opportunity costs as described in Section III.A.15.2(iii), for the Resource for the applicable Operating Days, with supporting data and calculations for those costs; (ii) regarding actual costs, an explanation of (a) why ~~the~~ such actual costs ~~of operating the Resource~~ exceeded the Reference Level or Day-Ahead Ancillary Services Benchmark Level costs or, (b) in the absence of mitigation, why ~~the~~ such 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) sufficient documentation and information supporting the basis for the original offer at the time the offer was submitted; (iv) an explanation as to why the original offer should not have been mitigated to the applicable Reference Level or Benchmark Level, or in the absence of mitigation, why the Section III.A.15.1 request should not have been denied in whole or in part; (v~~iii~~) the Internal Market Monitor's written explanation provided pursuant to Section III.A.15.2.2~~3~~; and (~~i~~vi) 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), (iii), and (iv) 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 Competitiveness of Markets.

In furtherance of its function 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 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 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, as amended from time to time and available on the ISO's website. Consistent with the ISO New England Inc. Code of Conduct, at a minimum each such monitoring unit and its employees: (a) must have no material affiliation with any Market Participant or Affiliate, (b) must have no material financial interest in any Market Participant or Affiliate with potential exceptions for mutual funds and non-directed investments, (c) must not engage in any market transactions other than the performance of their duties hereunder, (d) may not accept anything of value from a Market Participant in excess of a *de minimis* amount, and (e) must advise a supervisor in the event they seek employment with a Market Participant, and must disqualify themselves from participating in any matter that would have an effect on the financial interest of the Market Participant.

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 certain New Capacity Resources in the Forward Capacity Auction as described in this Section III.A.21. The provisions of Sections III.A.21.1 and III.A.21.2 are not applicable to offers from New Import Capacity Resources that are subject to the pivotal supplier test in Section III.A.23.

III.A.21.1. Applicability of Buyer-Side Market Power Review.

The Internal Market Monitor will not conduct a buyer-side market power review of New Capacity Resources that meet the criteria described in this Section III.A.21.1.

III.A.21.1.1. Resources with Capacity Not Exceeding 5 MW.

A New Capacity Resource will not be subject to the Internal Market Monitor's buyer-side market power review if the project's expected auction capacity (in MW) at the time of the qualification process for the Forward Capacity Auction does not exceed 5 MW.

If a New Capacity Resource's expected auction capacity exceeds 5 MW at the time of the qualification process for the Forward Capacity Auction, but the final FCA Qualified Capacity for the New Capacity Resource does not exceed 5 MW, an offer from the New Capacity Resource will not be mitigated pursuant to Section III.A.21.2.3, notwithstanding any buyer-side market power review that may have been conducted at the time of the qualification process.

III.A.21.1.2. Passive Demand Response Resources.

New Demand Capacity Resources that consist solely of On-Peak Demand Resources or Seasonal Peak Demand Resources will not be subject to the Internal Market Monitor's buyer-side market power review.

III.A.21.1.3. Resources Supported by a Qualifying Load-Side Relationship Certification.

New Capacity Resources will not be subject to the Internal Market Monitor's buyer-side market power review if the Project Sponsor submits a Load-Side Relationship Certification, as described in this Section III.A.21.1.3, demonstrating one of the following qualifying circumstances:

(a) the Project Sponsor and its Affiliates or partners, if any, are not load serving entities and are neither receiving nor expecting to receive any revenues from a load serving entity, state, or political subdivision of a state that relate to the development, operation, control, or output of the New Capacity Resource (excepting any revenues earned through an ISO-administered market); or

(b) the New Capacity Resource is a Sponsored Policy Resource.

For the purpose of this Section III.A.21, a load serving entity is any entity that has or is the type of entity that could acquire a Capacity Load Obligation in the Forward Capacity Market.

To demonstrate such circumstances, the Project Sponsor must include as part of the Load-Side Relationship Certification a sworn affidavit from an officer or principal for the Project Sponsor that includes factual detail sufficient to explain the qualifying circumstances. The Project Sponsor must submit the Load-Side Relationship Certification with the New Capacity Qualification Package, described in Section III.13.1.1.2.2, the New Demand Capacity Resource Qualification Package, described in Section III.13.1.4.1.1.2, or the New Distributed Energy Capacity Resource Qualification Package, described in Section III.13.1.4A.1.1.2. If the ISO is unable to determine from the Load-Side Relationship Certification that one of the qualifying circumstances exists, the New Capacity Resource’s offer shall be subject to buyer-side market power review pursuant to Section III.A.21.2.

III.A.21.2. Review for the Exercise of Buyer-Side Market Power.

With the exception of New Capacity Resources that meet the criteria described in Section III.A.21.1, the Internal Market Monitor shall review requested lowest offer prices from New Capacity Resources, as described in Sections III.13.1.1.2.2.3(a), III.13.1.4.1.1.2.8(a), and III.13.1.4A.1.1.2.6(a), for the potential exercise of buyer-side market power following the process described in this Section III.A.21.2.

III.A.21.2.1. Conduct Test.

The Internal Market Monitor will perform a conduct test by reviewing the information described in Sections III.13.1.1.2.2.3(a), III.13.1.4.1.1.2.8(a), and III.13.1.4A.1.1.2.6(a) and determining a New Resource Offer Floor Price, as described in Section III.A.21.3, for the New Capacity Resource. A requested lowest offer price from a New Capacity Resource fails the conduct test if the Internal Market Monitor determines that the New Resource Offer Floor Price exceeds the requested lowest offer price.

III.A.21.2.2. Demonstration of Lack of Incentive to Exercise Buyer-Side Market Power.

If the Project Sponsor does not submit a Load-Side Relationship Certification (or the ISO rejects the Project Sponsor’s Load-Side Relationship Certification) because the Project Sponsor is or is affiliated with a load serving entity or because the Project Sponsor receives or expects to receive revenues outside of ISO-administered markets from a load serving entity, the Project Sponsor is entitled to submit documentation and information as part of the New Capacity Qualification Package, the New Demand Capacity Resource Qualification Package, or New Distributed Energy Capacity Resource Qualification Package to demonstrate that, notwithstanding such a relationship with a load serving entity with regard to the New Capacity Resource, such load serving entity would be unlikely to realize a material, net financial benefit from any reduction in Forward Capacity Auction clearing prices resulting from entry of the New Capacity Resource in the Forward Capacity Market. If, after consideration of such documentation and information, the Internal Market Monitor determines that a load serving entity as described in this Section III.A.21.2.2 would be unlikely to realize a material, net financial benefit from any reduction in Forward Capacity Auction clearing prices resulting from entry of the New Capacity Resource in the Forward Capacity Market, then the Internal Market Monitor will not subject the requested lowest offer price to the mitigation described in Section III.A.21.2.3. For the avoidance of doubt, a Project Sponsor may not utilize the provisions of this Section III.A.21.2.2 if it receives or expects to receive any revenues from a state, or from a political subdivision of a state that is not also a load serving entity, that relate to the development, operation, control, or output of the New Capacity Resource.

As part of the documentation and information the Project Sponsor submits pursuant to this Section III.A.21.2.2, the Project Sponsor must include in its documentation and information a disclosure of any and all direct or indirect relationships or arrangements with a load serving entity regarding the New Capacity Resource and any other information necessary for the Internal Market Monitor to make the determination described in this Section III.A.21.2.2.

III.A.21.2.3. Consequence of Failing the Conduct Test and Failing to Rebut Presumed Incentive.
If a requested lowest offer price from a New Capacity Resource fails the conduct test and the Internal Market Monitor does not determine the lack of a material, net financial benefit to a load serving entity, as described in Section III.A.21.2.2, the New Resource Offer Floor Price calculated as part of the conduct test shall be used in the Forward Capacity Auction, as described in Section III.13.2.3.2.

As described in Section III.A.21.1.1, the mitigation described in this Section III.A.21.2.3 will not apply to a New Capacity Resource with an FCA Qualified Capacity that does not exceed the capacity threshold set forth in Section III.A.21.1.1, notwithstanding the results of any buyer-side market power review.

III.A.21.3. New Resource Offer Floor Prices.
For any New Capacity Resource for which the Internal Market Monitor is required to calculate a New Resource Offer Floor Price, the Internal Market Monitor shall use the calculation methodology described in this Section III.A.21.3.

A resource having a New Resource Offer Floor Price determined pursuant to this Section III.A.21.3 that is higher than the Forward Capacity Auction Starting Price shall not be included in the Forward Capacity Auction.

(a) When calculating a New Resource Offer Floor Price for any New Capacity Resource, the Internal Market Monitor shall enter all relevant resource capital and operating costs and non-capacity revenue data, as well as assumptions regarding depreciation, taxes, and discount rate into a capital budgeting model 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 default 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). The model horizon shall be longer or shorter than 20 years for a resource's New Resource Offer Floor Price calculation, if sufficiently documented in the offer information submitted pursuant to Sections III.13.1.1.2.2.3, III.13.1.4.1.1.2.8, or III.13.1.4A.1.1.2.6. Adjustments to the model and calculation methodology will be made for certain types of New Demand Capacity Resources and New Distributed Energy Capacity Resources as described below in this subsection (a):

(i) For Demand Response Assets or Distributed Energy Resources with demand reduction capability, the Internal Market Monitor will model discounted cash flows over the contract life.

(ii) For Demand Response Assets or Distributed Energy Resources with demand reduction capability that are large commercial or industrial customers that use pre-existing equipment or strategies, the Internal Market Monitor will include new equipment costs and annual operating costs, such as customer incentives and sales representative commissions, as incremental costs.

(iii) For Demand Response Assets or Distributed Energy Resources with demand reduction capability that are residential or small commercial customers that do not use pre-existing equipment or strategies, the Internal Market Monitor will include equipment costs, customer incentives, marketing, sales, and recruitment costs, operations and maintenance costs, and software and network infrastructure costs as incremental costs.

(b) The Internal Market Monitor shall compare the requested lowest offer price to the capacity price estimate calculated pursuant to subsection (a), and the resource's New Resource Offer Floor Price 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 or New Distributed Energy 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 or Distributed Energy 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 or Distributed Energy Resource Aggregation, 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 (as described in Sections III.13.1.1.2.2.3(a), III.13.1.4.1.1.2.8(a), or III.13.1.4A.1.1.2.6(a)) to allow the Internal Market Monitor to make the determinations described in this Section III.A.21.3. If the supporting documentation and information 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 Forward Capacity Auction Starting Price.

(v) If the Internal Market Monitor determines that the requested offer price is 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.

(vi) If the Internal Market Monitor determines that the requested offer price is not consistent with the Internal Market Monitor's capacity price estimate, then the New Resource Offer Floor Price 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).

III.A.21.4. Offer Prices for New Import Capacity Resources.

(a) All New Import Capacity Resources (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 subject to the pivotal supplier test in Section III.A.23.

(b) For any New Import Capacity Resource that is subject to the pivotal supplier test in Section III.A.23 that does not seek to specify a price below which it would not accept a Capacity Supply Obligation that is at or above the Dynamic De-List Bid Threshold, the resource's offer price shall be $0.00/kW-month, subject to the provisions of Section III.13.2.3.2(a)(v).

(c) For any New Import Capacity Resource that is subject to the pivotal supplier test in Section III.A.23 and seeks to specify a price below which it would not accept a Capacity Supply Obligation that is at or above the Dynamic De-List Bid Threshold, the Internal Market Monitor shall calculate an Internal Market Monitor-determined offer price for the resource using the methodology for calculating New Resource Offer Floor Prices set forth in Section III.A.21.3. For any New Import Capacity Resource that is not subject to the pivotal supplier test in Section III.A.23, the Internal Market Monitor shall calculate a New Resource Offer Floor Price using the methodology set forth in Section III.A.21.3, if such a calculation is required for the resource under Section III.A.21.2 above.

(d) For any New Import Capacity Resource that is subject to the pivotal supplier test in Section III.A.23 and is found to be associated with a pivotal supplier, if the supplier elects to revise the requested offer prices pursuant to Section III.13.1.3.5.7, the resource's offer prices shall be reduced to equal the lower of (1) the prices determined by the Internal Market Monitor pursuant to subsection (c); or (2) the offer prices as revised pursuant to Section III.13.1.3.5.7. For any New Import Capacity Resource that is subject to the pivotal supplier test and is found not to be associated with a pivotal supplier, if the supplier elects to revise the requested offer prices pursuant to Section III.13.1.3.5.7, the resource's offer prices shall be reduced to the prices revised pursuant to Section III.13.1.3.5.7.

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.

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.

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 Distributed Energy Resource participating as part of Demand Response Distributed Energy Resource Aggregation, a Settlement Only Distributed Energy Resource Aggregation, 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.

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.

Benchmark Scenario is an Economic Study reference scenario that is described in Section 17.2(a) of Attachment K to the OATT.

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, the demand reduction capability of a Demand Response Resource, or the demand reduction capability and energy injection capability of a Demand Response Distributed Energy Resource Aggregation.

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.

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.

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.

Cyber Security Exigency is a suspicious or malicious electronic act or event that compromises or attempts to compromise, or disrupts or attempts to disrupt, the ongoing operation of the ISO, the New England Markets, or reliability within the New England Control Area or other electrical facilities directly or indirectly connected to the New England Transmission System and (i) whose severity or nature reasonably requires that the ISO obtain expert assistance not normally called upon to counter such an electronic act or resolve such an event or (ii) whose nature requires the ISO to report such an electronic act or event pursuant to NERC Critical Infrastructure Protection Reliability Standards or applicable regulations promulgated by the Department of Homeland Security, the Department of Energy, or a federal agency with similar cybersecurity responsibilities (or any of their respective successor organizations or agencies).

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 Flexible Response Services and Day-Ahead Energy Imbalance Reserve.

Day-Ahead Ancillary Services Avoidable Input Cost is defined in Section III.A.8.2.2 of Appendix A of Market Rule 1.

Day-Ahead Ancillary Services Benchmark Level is defined in Section III.A.8.2 of Appendix A of Market Rule 1.

Day-Ahead Ancillary Services Expected Close-Out Component is defined in Section III.A.8.2.1 of Appendix A of Market Rule 1.

Day-Ahead Ancillary Services Market means the sale of and payment for Day-Ahead Ancillary Services 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 Ancillary Services Offer is an offer that may be submitted by Market Participants in the Day-Ahead Ancillary Services Market in accordance with Section III.1.8.1 of Market Rule 1, and that is used by the ISO to determine obligations for Day-Ahead Ancillary Services as described in Section III.3.2.1(a)(2) of Market Rule 1.

Day-Ahead Ancillary Services Strike Price is specified in Section III.1.8.2 of Market Rule 1.

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 Ancillary Services Market to help satisfy the Forecast Energy Requirement Demand Quantity described in Section III.1.8.4 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 the schedule of commitments for the purchase or sale of energy, purchase of demand reductions, payment of Congestion Costs, 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 Flexible Response Services means Day-Ahead Ten-Minute Spinning Reserve, Day-Ahead Ten-Minute Non-Spinning Reserve, and Day-Ahead Thirty-Minute Operating Reserve.

Day-Ahead Flexible Response Services Demand Quantities means Day-Ahead Ten-Minute Spinning Reserve Demand Quantity, Day-Ahead Total Ten-Minute Reserve Demand Quantity, Day-Ahead Minimum Total Reserve Demand Quantity, and Day-Ahead Total Reserve Demand Quantity.

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 Market means the jointly optimized Day-Ahead Energy Market and Day-Ahead Ancillary Services Market.

Day-Ahead Minimum Total Reserve Demand Quantity is described in Section III.1.8.3(c) of Market Rule 1.

Day-Ahead Prices means the prices resulting from the Day-Ahead Market as described in Section III.2.6 of Market Rule 1.

Day-Ahead Ten-Minute Non-Spinning Reserve is a form of ten-minute reserve capability that is procured in the Day-Ahead Ancillary Services Market based on the system-wide requirements described in Section III.1.8.3 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 Ancillary Services Market based on the system-wide requirements described in Section III.1.8.3 of Market Rule 1.

Day-Ahead Ten-Minute Spinning Reserve Demand Quantity is described in Section III.1.8.3(a) of Market Rule 1.

Day-Ahead Ten-Minute Spinning Reserve Obligation is described 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 Ancillary Services Market based on the system-wide requirements described in Section III.1.8.3 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 Ten-Minute Reserve Demand Quantity is described in Section III.1.8.3(b) of Market Rule 1.

Day-Ahead Total Reserve Demand Quantity is described in Section III.1.8.3(d) 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 Distributed Energy Resource Aggregation (DRDERA) is a type of Distributed Energy Resource Aggregation that is described in additional detail in Section III.6.5.

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 Energy Capacity Resource (DECR) means an Existing Distributed Energy Capacity Resource or a New Distributed Energy Capacity Resource.

Distributed Energy Resource (DER) is any resource located on the distribution system, any subsystem thereof or behind a customer meter that is capable of providing energy injection, energy withdrawal, regulation, or demand reduction.

Distributed Energy Resource Aggregation (DERA) is an aggregation of Distributed Energy Resources that is registered under Section III.6.7 and is described in additional detail in Section III.6.

Distributed Energy Resource Aggregator (DER Aggregator) is a Market Participant that aggregates one or more Distributed Energy Resources for participation in a Distributed Energy Resource Aggregation and serves as the Lead Market Participant for a Distributed Energy Resource Aggregation.

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, Existing Demand Capacity Resources, and Existing Distributed Energy 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 or Economic Studies are studies described in Section 17 of Attachment K to the OATT that are used to examine situations where potential regulated transmission solutions, market responses, or investments could result in (i) a net reduction in total production cost to supply system load based on the factors specified in Attachment N of the OATT, (ii) reduced congestion, or (iii) the integration of new resources or loads, or both, on an aggregate or regional basis.

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 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 Distributed Energy Capacity Resource is a type of Distributed Energy Capacity Resource participating in the Forward Capacity Market, as defined in Section III.13.1.4A.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.1.8.4 of Market Rule 1.

Forecast Energy Requirement Penalty Factor is a rate, in $/MWh, that is used within the Day-Ahead Market security-constrained economic commitment and dispatch process to reflect the value of forecast energy requirement shortages and is defined in Section III.2.6.2(d) of Market Rule 1.

Forecast Energy Requirement Price is determined in accordance with Section III.2.6.2(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. As described in Section III.9.1, the final Forward Reserve Procurement Period shall run from October 1, 2024 through February 28, 2025.

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 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 or an aggregation of wind, solar, run of river hydro and other renewable resources 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, Demand Reduction Offers, Baseline Deviation Offers, or Day-Ahead Ancillary Services 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-Side Relationship Certification is a certification described in Section III.A.21.1.3 that a Project Sponsor submits as part of the New Capacity Qualification Package, New Demand Capacity Resource Qualification Package, or New Distributed Energy Capacity Resource Qualification Package to demonstrate that the New Capacity Resource should not be subject to buyer-side market power review.

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.

Longer-Term Transmission Study is a study conducted by the ISO pursuant to the process set out in Section 16 of Attachment K of the OATT. The 2050 Transmission Study shall be the first Longer-Term Transmission Study.

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 Needs Scenario is an Economic Study reference scenario that is described in Section 17.2(b) of Attachment K to the OATT.

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 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 Award Limit is a parameter that may be submitted as part of a Day-Ahead Ancillary Services Offer, as described in Section III.1.8.1, that expresses the maximum total megawatt-hours of Day-Ahead energy offered or bid and Day-Ahead Ancillary Services offered for the next Operating Day.

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 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 ninth 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 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 to be economically viable given reasonable expectations of the energy and ancillary services revenues under long-term equilibrium conditions.

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, New Demand Capacity Resource, or New Distributed Energy 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, a New Demand Capacity Resource Show of Interest Form, or a New Distributed Energy 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 Distributed Energy Capacity Resource is a type of Distributed Energy Capacity Resource participating in the Forward Capacity Market, as defined in Section III.13.1.4A.1 of Market Rule 1.

New Distributed Energy Capacity Resource Qualification Package is the information that a Project Sponsor must submit, in accordance with Section III.13.1.4A.1.1.2 of Market Rule 1, for each resource that it seeks to offer in the Forward Capacity Auction as a New Distributed Energy Capacity Resource.

New Distributed Energy Capacity Resource Show of Interest Form is described in Section III.13.1.4A.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.21.3.

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.

Permanent De-list Bid is a bid that may be submitted by an Existing Generating Capacity Resource, Existing Import Capacity Resource, Existing Demand Capacity Resource, or Existing Distributed Energy 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.

Policy Scenario is an Economic Study reference scenario that is described in Section 17.2(c) of Attachment K to the OATT.

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, New Demand Capacity Resource, or New Distributed Energy 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 an 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 SATOA Obligation is defined in Section III.3.2.1(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.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). 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. A Network Customer's Monthly Regional Network Load shall be calculated in accordance with Section II.21.2 of the OATT.

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 that are used within the Day-Ahead Market security-constrained economic commitment and dispatch process to reflect the value of Day-Ahead Flexible Response Services shortages and defined in Section III.2.6.2(c) 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, a Demand Response Resource, a Settlement Only Distributed Energy Resource Aggregation, or a Demand Response Distributed Energy Resource Aggregation.

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, Existing Demand Capacity Resource, or Existing Distributed Energy 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.

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 officer.

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 Distributed Energy Resource Aggregation (SODERA) is a type of Distributed Energy Resource Aggregation and is described in additional detail in Section III.6.6.

Settlement Only Resources are generators of less than 5 MW of maximum net output when operating at any temperature at or above zero degrees Fahrenheit, that meet the metering, interconnection and other requirements 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.

Solar High Limit is the estimated power output (MW) of a solar Generator Asset given the Real-Time solar and weather conditions, taking into account equipment outages, and absent any self-imposed reductions in power output or any reduction in power output as a result of a Dispatch Instruction, calculated in the manner described in the ISO Operating Documents.

Solar Plant Future Availability is the forecasted Real-Time High Operating Limit of a solar Generator Asset, calculated in the manner described in the ISO Operating Documents.

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, each asset of which: receives a revenue source, other than revenues from ISO-administered markets, that is supported by a government-regulated rate, charge, or other regulated cost recovery mechanism, and; qualifies as a renewable, clean, zero carbon, or alternative energy asset under a renewable energy portfolio standard, clean energy standard, decarbonization or net-zero carbon standard, alternative energy portfolio standard, renewable energy goal, clean energy goal, or decarbonization or net-zero carbon goal enacted by federal or New England state statute, regulation, or executive or administrative order and as a result of which the asset receives the revenue source.

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.

Stakeholder-Requested Scenario is an Economic Study reference scenario that is described in Section 17.2(d) of Attachment K to the OATT.

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.

State-identified Requirement refers to a legal requirement, mandate or policy of a New England state or local government that forms the basis for a Longer-Term Transmission Study request submitted to the ISO pursuant to the process set out in Section 16 of Attachment K of the OATT.

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, Existing Demand Capacity Resource, or Existing Distributed Energy 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 as Transmission-Only Asset (SATOA) is electric storage equipment that: (1) is connected to or to be connected to Pool Transmission Facilities in the New England Transmission System at a voltage level of 115 kV or higher; (2) the ISO approved to be included in the Regional System Plan and RSP Project List as a regulated transmission solution and Pool Transmission Facility pursuant to the regional system planning processes in Attachment K of the OATT; and (3) is capable of receiving energy only from the Pool Transmission Facilities and storing the energy for later injection to the Pool Transmission Facilities.

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.

Wind High Limit is the estimated power output (MW) of a wind Generator Asset given the Real-Time weather conditions, taking into account equipment outages, and absent any self-imposed reductions in power output or any reduction in power output as a result of a Dispatch Instruction, calculated in the manner described in the ISO Operating Documents.

Wind Plant Future Availability is the forecasted Real-Time High Operating Limit of a wind Generator Asset, calculated in the manner described in the ISO Operating Documents.

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.

Table of Contents

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 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. The ISO shall use a joint optimization process to serve Day-Ahead Market energy requirements and Day-Ahead Ancillary Services requirements, as described in Section III.1.10.8(a).

(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 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 LMP-Based 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.1.7.9 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.1.7.9A 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.1.7.10 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 potential referral under Section III.A.19.

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.1.7.21 SATOA Participation in Markets: A Node will be established for each SATOA. A Market Participant's market activity, transactions, and actions taken at a SATOA's Node and a SATOA's participation in the New England Markets shall be limited to those necessary to consume or inject energy from or to PTF for any period, magnitude, and duration identified as necessary to: (1) address the applicable system needs or provide the transmission function for which the SATOA was selected as the preferred solution; or (2) as specified in the ISO New England Operating Documents, avoid or mitigate Load Shedding after all available Dispatchable Resources that can effectively provide relief to avoid or mitigate the Load Shedding have been dispatched.

III.1.8 Day-Ahead Ancillary Services and Forecast Energy Requirement.

III.1.8.1 Day-Ahead Ancillary Services Offers.

Market Participants may submit Day-Ahead Ancillary Services Offers for the Operating Day in the Day-Ahead Ancillary Services Market as specified in this Section III.1.8.1.

(a) Each Day-Ahead Ancillary Services Offer shall be associated with a specific Generator Asset, Demand Response Resource, or DARD for which the Market Participant has submitted a corresponding

Supply Offer, Demand Reduction Offer, or Demand Bid in the Day-Ahead Energy Market for the same hour of the Operating Day.

(b) Each Day-Ahead Ancillary Services Offer shall specify: (i) the hour of the Operating Day for which the Day-Ahead Ancillary Services Offer applies; (ii) product-specific offer prices, in $/MWh, that are greater than or equal to zero for the Day-Ahead Ancillary Services; and (iii) a single offer quantity, in MWh, that is greater than or equal to zero. The offer prices for the Day-Ahead Ancillary Services shall not exceed the Forecast Energy Requirement Penalty Factor as specified in Section III.2.6.2(d) of this Market Rule 1. The offer quantity shall not exceed the Economic Maximum Limit specified in the associated Supply Offer, the Maximum Reduction specified in the associated Demand Reduction Offer, or the Maximum Consumption Limit specified in the associated Demand Bid.

(c) As part of its Day-Ahead Ancillary Services Offer, a Market Participant is permitted to specify a Maximum Daily Award Limit quantity, in MWh, that is greater than or equal to zero.

(d) For each hour of the Operating Day, a Market Participant may submit only one Day-Ahead Ancillary Services Offer associated with a specific Generator Asset, Demand Response Resource, or DARD.

(e) Day-Ahead Ancillary Services Offers shall be submitted by the offer submission deadline for the Day-Ahead Market specified in Section III.1.10.1A of this Market Rule 1. A Day-Ahead Ancillary Services Offer shall not remain in effect for subsequent Operating Days.

III.1.8.2 Day-Ahead Ancillary Services Strike Price.

(a) For each hour of the Operating Day, the ISO shall specify the Day-Ahead Ancillary Services Strike Price in $/MWh. The value of the Day-Ahead Ancillary Services Strike Price represents an amount that is the greater of (i) $10/MWh greater than a forecast of the expected hourly Real-Time Hub Price for such hour of the Operating Day and (ii) zero.

(b) The forecast used to determine the Day-Ahead Ancillary Services Strike Price shall be based on a publicly-available forecasting algorithm developed by the ISO. The ISO shall describe the publicly-available forecasting algorithm to Market Participants and shall periodically review and assess the efficacy of the forecasting algorithm. The ISO shall notify stakeholders of any potential revisions to the ISO’s forecasting algorithm prior to implementing such revisions.

(c) In the event that the ISO is not able to utilize the ISO-developed forecasting algorithm described in subsection (b) above due to hardware, software, or telecommunications problems, human error, or exigent circumstances not contemplated by this market rule, the ISO shall determine the Day-Ahead Ancillary Services Strike Price using the best forecast available and shall disclose the use of such substitute forecast to Market Participants as soon as practicable.

III.1.8.3 Day-Ahead Flexible Response Services Demand Quantities.

The Day-Ahead Ancillary Services Market shall endeavor to procure the Day-Ahead Flexible Response Services Demand Quantities specified in this Section III.1.8.3.

(a) For each hour of the Operating Day, the Day-Ahead Ten-Minute Spinning Reserve Demand Quantity shall be equal to the Ten-Minute Spinning Reserve Requirement projected Day-Ahead.

(b) For each hour of the Operating Day, the Day-Ahead Total Ten-Minute Reserve Demand Quantity shall be equal to the Ten-Minute Reserve Requirement projected Day-Ahead.

(c) For each hour of the Operating Day, the Day-Ahead Minimum Total Reserve Demand Quantity shall be equal to the Minimum Total Reserve Requirement projected Day-Ahead.

(d) For each hour of the Operating Day, the Day-Ahead Total Reserve Demand Quantity shall be equal to the Total Reserve Requirement projected Day-Ahead.

III.1.8.4 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 load in the New England Control Area produced pursuant to Section III.1.10.1A(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 and Demand Reduction 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 the Day-Ahead Market and a Real-Time Energy Market.

(b) The Day-Ahead Market shall enable Market Participants to purchase and sell energy and sell ancillary services through the New England Markets at 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 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 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 and Day-Ahead Ancillary Services Market Scheduling.

Market Participants may submit offers and bids in the Day-Ahead Market until 10:30 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 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</u>

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) **Day-Ahead Ancillary Services Offers** – Market Participants selling into the New England Markets from Generator Assets or Demand Response Resources or participating in the New England Markets with DARDs, and that have submitted Supply Offers, Demand Reduction Offers, or Demand Bids for the following Operating Day, as described in subsections (c), (d), and (e) of this Section III.1.10.1A, may submit Day-Ahead Ancillary Services Offers for the following Operating Day. Day-Ahead Ancillary Services Offers shall be submitted to the ISO in accordance with Section III.1.8.1 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, ancillary services, 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 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 Market consistent with the Supply Offers and Demand Reduction Offers of other Resources, the submitted Demand Bids and Decrement Bids, ancillary services offers and requirements, and the Forecast Energy Requirement Demand Quantity.

(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 and storing the energy for later injection of electricity into 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 any 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 incapable of receiving and storing electricity from the grid may participate in the New England Markets as a Continuous Storage Facility, so long as that facility satisfies all Continuous Storage Facility registration and participation requirements that are not solely related to consumption capability. Notwithstanding Section III.1.10.6(a), Section III.1.10.6(c), and any other related provisions, such non-consuming storage facilities shall not be required to:

(i) be capable of consuming at least 0.1 MW from the grid; or

(ii) be capable of modifying consumption responsive to Dispatch Instructions.

(e) 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 energy shall not qualify as, or be billed to, a Storage DARD if that facility's charging energy is included in another 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 energy.

(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.

(f) 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.

(g) 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.

(h) 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.)

(i) 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.

(j) 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 Scheduling Considerations.

(a) In scheduling the Day-Ahead Market, the ISO shall use its best efforts to determine the security-constrained economic commitment and dispatch that jointly optimizes: (i) Demand Bids, Decrement Bids, Demand Reduction Offers, Supply Offers, Increment Offers, and External Transactions, for energy; (ii) Day-Ahead Ancillary Services Offers to satisfy the Day-Ahead Flexible Response Services Demand Quantities; and (iii) Supply Offers, Demand Reduction Offers, External Transactions, and Day-Ahead Ancillary Services Offers to satisfy the Forecast Energy Requirement Demand Quantity.

In making the determination specified in this subsection (a), the ISO shall take into account, as applicable: (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 ancillary services; (vi) the operational capabilities of any Resource to adjust the output, consumption, or demand reduction within the operating characteristics and parameters specified in the Market Participant's Offer Data, Supply Offer, Demand Reduction Offer, or Demand Bid and any audited values of such operating characteristics and parameters; (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.

In scheduling the Day-Ahead Market, the following limitations shall apply:

(i) For purposes of satisfying the Day-Ahead Flexible Response Services Demand Quantities specified in Sections III.1.8.3(a) through (d), the ISO shall not take into account a Day-Ahead

Ancillary Services Offer unless the Generator Asset, Demand Response Resource, or DARD associated with the Day-Ahead Ancillary Services Offer meets the eligibility requirements enumerated in Section III.1.7.19.1.

(ii) For purposes of satisfying the Forecast Energy Requirement Demand Quantity specified in Section III.1.8.4, the ISO shall not take into account a Day-Ahead Ancillary Services Offer unless the offer is associated with a Generator Asset or Demand Response Resource that meets the following conditions:

(1) The Generator Asset or Demand Response Resource is, for the applicable hour, either scheduled for energy in the Day-Ahead Energy Market or is a Fast Start Generator or Fast Start Demand Response Resource.

(2) The Generator Asset or Demand Response Resource is not designated as constrained by transmission limitations, as described in Section III.1.7.19.1(3).

(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 and ancillary services 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 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 and ancillary services scheduled in the Day-Ahead Market based upon 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, and nuclear-powered 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, solar, 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 Market Participant may elect, but is not required, to have a wind, solar, 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.

(ii) 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.

(c) Wind and solar Generator Assets that are not Settlement Only Resources shall electronically transmit meteorological and forced outage data, as specified below, to the ISO, over a secure network, using the protocol specified in the ISO Operating Documents, for the development and deployment of wind and solar power production forecasts.

Wind Generator Assets that are not Settlement Only Resources shall provide the ISO with the following site-specific meteorological and forced outage data in the manner described in the ISO Operating Documents:

(i) at least once every 30 seconds: wind speed, and wind direction;

(ii) at least once every 5 minutes: ambient air temperature, standard deviation of ambient air temperature, ambient air pressure, standard deviation of ambient air pressure, ambient air relative humidity, and standard deviation of ambient air relative humidity;

(iii) at least once every 5 minutes: Real-Time High Operating Limit, Wind High Limit, wind turbine counts; and

(iv) at least once every hour at the top of the hour for the next 48 hours and by 1000 each day for the next 49 to 168 hours: Wind Plant Future Availability.

Solar Generator Assets that are not Settlement Only Resources shall provide the ISO with the following site-specific meteorological and forced outage data in the manner described in the ISO Operating Documents:

(i) at least once every 30 seconds: irradiance;

(ii) at least once every 5 minutes: ambient air temperature, standard deviation of ambient air temperature, ambient air pressure, standard deviation of ambient air pressure, ambient air relative humidity, standard deviation of ambient air relative humidity, wind speed, and wind direction;

(iii) at least once every 5 minutes: Real-Time High Operating Limit, and Solar High Limit; and

(iv) at least once every hour at the top of the hour for the next 48 hours and by 1000 each day for the next 49 to 168 hours: Solar Plant Future Availability.

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. 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 Market.

III.2.2 General.

The ISO shall determine the least cost security-constrained economic 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, Day-Ahead Ancillary Services prices, and the Forecast Energy Requirement Price will be calculated based on the joint optimization process described in Section III.1.10.8(a) utilizing the prices of offers and bids, the Forecast Energy Requirement Penalty Factor as specified in Section III.2.6.2(d) when applicable, and Reserve Constraint Penalty Factors as specified in Section III.2.6.2(c) when applicable. 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.

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, Real-Time Reserve Clearing Prices, 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) Day-Ahead Locational Marginal Prices shall be determined on the basis of the Day-Ahead Market security-constrained economic commitment and dispatch described in Section III.1.10.8(a) and in accordance with the provisions of this Section applicable to the Day-Ahead Energy Market. Such prices 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 Market by applying a joint optimization method consistent with Section III.1.10.8(a), 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 Day-Ahead Ancillary Services 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 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 cost of serving an increment of load at a Node or External Node, 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.

The ISO shall calculate hourly Day-Ahead Prices for additional requirements in the Day-Ahead Market as described in this Section III.2.6.2.

(a) **Day-Ahead Flexible Response Services Clearing Prices.**

(i) The clearing price for Day-Ahead Thirty-Minute Operating Reserve shall be the incremental cost, as measured by the change in the Day-Ahead Market security-constrained economic dispatch objective value, to satisfy:

(1) the next increment of Day-Ahead Minimum Total Reserve Quantity, if the cost of such next increment is greater than or equal to the Reserve Constraint Penalty Factor applicable to the Day-Ahead Total Reserve Demand Quantity; or,

(2) if Section III.2.6.2(a)(i)(1) is inapplicable, the next increment of Day-Ahead Total Reserve Demand Quantity.

(ii) The clearing price for Day-Ahead Ten-Minute Non-Spinning Reserve shall be the sum of (1) the incremental cost, as measured by the change in the Day-Ahead Market security-constrained economic dispatch objective value, to satisfy the next increment of the Day-Ahead Total Ten-Minute Reserve Demand Quantity, and (2) the clearing price for Day-Ahead Thirty-Minute Operating Reserve.

(iii) The clearing price for Day-Ahead Ten-Minute Spinning Reserve shall be the sum of (1) the incremental cost, as measured by the change in the Day-Ahead Market security-constrained economic dispatch objective value, to satisfy the next increment of Day-Ahead Ten-Minute Spinning Reserve, and (2) the clearing price for Day-Ahead Ten-Minute Non-Spinning Reserve.

(iv) If the Day-Ahead Market does not clear sufficient Day-Ahead Flexible Response Services to satisfy one or more of the Day-Ahead Flexible Response Services Demand Quantities, the Day-Ahead Flexible Response Services clearing prices shall be set based upon the applicable Reserve Constraint Penalty Factors, as described by Section III.2.6.2(c)(i) through (iv).

(b) **Forecast Energy Requirement Price**.

(i) The Forecast Energy Requirement Price shall be the marginal cost, as measured by the change in the Day-Ahead Market security-constrained economic dispatch objective value, to satisfy the next increment of the Forecast Energy Requirement Demand Quantity.

(ii) The Forecast Energy Requirement Price shall be based upon the Forecast Energy Requirement Penalty Factor specified by Section III.2.6.2(d) when any one or some combination of the following occurs:

(1) The Day-Ahead Market does not clear sufficient energy and Day-Ahead Energy Imbalance Reserve to satisfy the Forecast Energy Requirement Demand Quantity.

(2) The Day-Ahead Locational Marginal Prices are set pursuant to Section III.2.6.1(b).

(c) **Reserve Constraint Penalty Factors in the Day-Ahead Market**. The Day-Ahead Market scheduling pursuant to Section III.1.10.8(a), 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 Minimum Total 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 Reserve Demand Quantity shall be equal to the Real-Time Total Reserve Requirement Reserve Constraint Penalty Factor specified in Section III.2.7A.

(d) **Forecast Energy Requirement Penalty Factor**. The Day-Ahead Market scheduling pursuant to Section III.1.10.8(a), and the Day-Ahead Prices specified in Section III.2.6, shall respect the Forecast Energy Requirement Penalty Factor applicable to the Forecast Energy Requirement Demand Quantity. The Forecast Energy Requirement Penalty Factor shall be set at $2,575/MWh.

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 in Real-Time 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 Market Results

(a) Day-Ahead 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 Market results for an Operating Day or if no Day-Ahead 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 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 Market results and shall post a notice stating its findings.

(b) The ISO will publish corrected Day-Ahead Market results within three business days of the close of the applicable Operating Day or the results of the Day-Ahead Market for the Operating Day will stand; provided, however, in the event that the ISO is unable to calculate and post final Day-Ahead 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 Market results for an Operating Day, the ISO shall calculate corrected Day-Ahead 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 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 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 and Day-Ahead Ancillary Services 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 and Day-Ahead Ancillary Services 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 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 Ancillary Services Market Obligations** – Each Market Participant with a Day-Ahead Ancillary Services Offer that is accepted by the ISO in the Day-Ahead Ancillary Services 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 Day-Ahead Ancillary Services 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 Day-Ahead Ancillary Services Offer quantity that contributes to satisfying the Day-Ahead Total Ten-Minute Reserve Demand Quantity, and that same Day-Ahead Ancillary Services 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 Day-Ahead Ancillary Services Offer quantity that contributes to satisfying the Day-

Ahead Total Reserve Demand Quantity, and that same Day-Ahead Ancillary Services 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 Energy Imbalance Reserve Obligation** – A Market Participant with an accepted Day-Ahead Ancillary Services 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 plus the Real-Time SATOA 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.

(vi) **Real-Time SATOA Obligation** – Each PTO shall have for each settlement interval a Real-Time SATOA Obligation for energy at each Location equal to the sum of: (1) the MWhs of energy, where such MWhs of energy shall have positive value, provided by SATOAs at that Location; and (2) the MWhs of load, where such MWhs of load shall have a negative value, consumed by SATOAs at that Location.

(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) **<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 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) **<u>Non-Market Participant Loss</u>** – 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) **<u>Inadvertent Energy Revenue</u>** – 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) **<u>Inadvertent Energy Revenue Charges or Credits</u>** – 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) **<u>Day-Ahead Ancillary Services Market Credit</u>** – 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).

(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).

(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).

(iv) **Day-Ahead Energy Imbalance Reserve Credit** – Each MWh of Day-Ahead Energy Imbalance Reserve Obligation shall be credited the Forecast Energy Requirement Price calculated in accordance with Section III.2.6.2(b).

(q)(2) **Day-Ahead Ancillary Services Market Close-Out Charge** – Each Market Participant with a Day-Ahead Ancillary Services obligation shall receive a charge as follows:

(i) **Day-Ahead Flexible Response Services Charge** – Each MWh of Day-Ahead Ten-Minute Spinning Reserve Obligation, Day-Ahead Ten-Minute Non-Spinning Reserve Obligation, and Day-Ahead Thirty-Minute Operating 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 Day-Ahead Ancillary Services Strike Price for the hour, and (b) zero.

(ii) **Day-Ahead Energy Imbalance Reserve Charge –** Each MWh of Day-Ahead Energy Imbalance Reserve Obligation shall be charged the close-out charge rate determined in accordance with Section III.3.2.1(q)(2)(i).

(q)(3) **Allocation of Day-Ahead Flexible Response Services Credits/Charges**

(i) The sum total credits calculated in accordance with Sections III.3.2.1(q)(1)(i) through (iii) for Day-Ahead Flexible Response Services 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 at all External Nodes (but not excluding the Real-Time Load Obligation incurred by Capacity Export Through Import Constrained Zone Transactions or FCA Cleared Export Transactions), and 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 Flexible Response Services 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 at all External Nodes (but not excluding the Real-Time Load Obligation incurred by Capacity Export Through Import Constrained Zone Transactions or FCA Cleared Export Transactions), and excluding Real-Time Load Obligation incurred by Storage DARDs.

(q)(4) **Allocation of Forecast Energy Requirement and Day-Ahead Energy Imbalance Reserve Credits/Charges**

(i) **Forecast Energy Requirement Credit for Generator Assets and Demand Response Resources** – Each Market Participant with a Generator Asset or Demand Response Resource scheduled in the Day-Ahead Energy Market shall be credited the Forecast Energy Requirement Price, calculated in accordance with Section III.2.6.2(b), for each MWh of the resource's Day-Ahead energy obligation.

(ii) **Forecast Energy Requirement Credit for External Transaction Purchases** – Each Market Participant with an External Transaction purchase scheduled in the Day-Ahead Energy Market for which a corresponding External Transaction also has been properly submitted in the Real-Time Energy Market and submitted in the appropriate external Control Area shall be credited the Forecast Energy Requirement Price, calculated in accordance with Section III.2.6.2(b), for the lesser of (a) each MWh of the Day-Ahead energy obligation associated with the External Transaction and (b) each MWh offered for the corresponding External Transaction in the Real-Time Energy Market.

(iii) **Forecast Energy Requirement and Day-Ahead Energy Imbalance Reserve Charges** – The total amount credited in accordance with Sections III.3.2.1(q)(4)(i), III.3.2.1(q)(4)(ii), and III.3.2.1(q)(1)(iv) shall be charged on an hourly basis as follows:

a. Each Market Participant with an External Transaction sale scheduled in the Day-Ahead Energy Market shall receive a charge at the Forecast Energy Requirement Price for each MWh of such External Transaction sale.

b. For the difference between the total amount credited and the total amount charged to Market Participants with External Transaction sales scheduled in the Day-Ahead Energy Market as described in this subsection (iii), Market Participants shall receive a charge based on their pro rata share of the sum of all Market Participants' Real-Time Load Obligation, excluding Real-Time Load Obligation incurred at all External Nodes, and excluding Real-Time Load Obligation incurred by Storage DARDs.

(iv) **Day-Ahead Energy Imbalance Close-Out Credits** – The sum total close-out charges calculated in accordance with Section III.3.2.1(q)(2)(ii) for Day-Ahead Energy Imbalance 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 at all External Nodes, and excluding Real-Time Load Obligation incurred by 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, Load Asset, and SATOA 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), each Asset Related Demand, and each SATOA 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 of an RBA form for a Meter Data Error as defined in Section 6.3.1 of the ISO New England Billing Policy, 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. 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, 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.9 Forward Reserve Market

The Forward Reserve Market is a market to procure TMNSR and TMOR on a forward basis to satisfy Forward Reserve requirements.

III.9.1 Forward Reserve Market Timing.

A Forward Reserve Auction will be held approximately two months in advance of each Forward Reserve Procurement Period. The Forward Reserve Auction input parameters and assumptions will be evaluated, published and reviewed with Market Participants prior to the Forward Reserve Auction. The final Forward Reserve Auction will be held approximately two months in advance of the final Forward Reserve Procurement Period as described in this Section III.9.1, and no Forward Reserve Auctions shall be conducted thereafter.

The Forward Reserve Procurement Periods shall be the Winter Capability Period (October 1 through May 31) or the Summer Capability Period (June 1 through September 30), as applicable. The final Forward Reserve Procurement Period shall run from October 1, 2024 through February 28, 2025.

The Forward Reserve Delivery Period shall be hour ending 0800 through hour ending 2300 for each weekday of the Forward Reserve Procurement Period excluding those weekdays that are defined as NERC holidays.

III.9.2 Forward Reserve Requirements.

The ISO shall conduct an advance purchase of capability to satisfy the expected Forward Reserve requirements for the system and each Reserve Zone as calculated by the ISO in accordance with the following procedures and as specified more fully in the ISO New England Manuals. The Forward Reserve requirements will be specified as part of the Forward Reserve Auction parameters and will be published and reviewed with Market Participants prior to each Forward Reserve Auction.

III.9.2.1 System Forward Reserve Requirements.

The Forward Reserve requirements for the New England Control Area will be based on the forecast of the first and second contingency supply losses for the next Forward Reserve Procurement Period and will consist of the following:

(i) One half of the forecasted first contingency supply loss will be specified as the minimum forward ten-minute reserve requirement to be purchased.

(ii) The minimum forward ten-minute reserve requirement described in subsection (i) will be increased if system conditions forecasted for the Forward Reserve Procurement Period indicate that the TMNSR available during the period would otherwise be insufficient to meet Real-Time Operating Reserve requirements. The increase shall be calculated to account for: (a) any historical under-performance of Resources dispatched in response to a System contingency and (b) the likelihood that more than one half of the forecasted first contingency supply loss will be satisfied using TMNSR.

(iii) The minimum forward ten-minute reserve requirement plus one half of the second contingency supply loss will be specified as the minimum forward total reserve requirement to be purchased.

(iv) The minimum forward total reserve requirement described in subsection (iii) will be increased by an amount of Replacement Reserve as specified in ISO New England Operating Procedure No. 8.

The requirements specified above, further adjusted to respect the additional provisions described in Section III.9.2.2, represent the set of requirements that will be input into the Forward Reserve Auction.

III.9.2.2 Zonal Forward Reserve Requirements.

Zonal Forward Reserve requirements will be established for each Reserve Zone. The zonal Forward Reserve requirements will reflect the need for 30-minute contingency response to provide 2nd contingency protection for each import constrained Reserve Zone. The zonal Forward Reserve requirements can be satisfied only by Resources that are located within a Reserve Zone and that are capable of providing 30-minute or higher quality reserve products.

The ISO shall establish the zonal Forward Reserve requirements based on a rolling, two-year historical analysis of the daily peak hour operational requirements for each Reserve Zone for like Forward Reserve Procurement Periods. The ISO will commence the analysis on February 1 or the first business day thereafter for the subsequent summer Forward Reserve Procurement Period and on June 1 or the first business day thereafter for the subsequent winter Forward Reserve Procurement Period.

These daily peak hour requirements will be aggregated into daily peak hour frequency distribution curves and the MW value at the 95th percentile of the frequency distribution curve for each Reserve Zone will establish the zonal requirement.

In the event of a change in the configuration of the transmission system or the addition, deactivation or retirement of a major Generator Asset, Dispatchable Asset Related Demand or Demand Response Resource the rolling two-year historical analysis will be calculated in a manner that reflects the change in configuration of the transmission system or the addition, deactivation or retirement of a major Generator Asset, Dispatchable Asset Related Demand or Demand Response Resource as of the commencement date of the analysis provided that the following conditions are met:

(a) Change in Configuration of the Transmission System

Any change in the configuration of the transmission system must have been placed in service and released for dispatch on or before December 31 for inclusion in the analysis for setting the zonal Forward Reserve requirements for the subsequent summer Forward Reserve Procurement Period or on or before April 30 for inclusion in the analysis for setting the zonal Forward Reserve requirements for the subsequent winter Forward Reserve Procurement Period.

If the change in the configuration of the transmission system consists of a new facility or upgrade of an existing facility, the facility must have operated at an availability level of at least 95% for the period beginning with its in service date and ending on January 31 prior to the summer Forward Reserve Procurement Period or ending on May 31 prior to the winter Forward Reserve Procurement Period.

(b) Addition, Deactivation or Retirement of a Major Generating Resource, Dispatchable Asset Related Demand or Demand Response Resource.

For the addition of a new Generator Asset, Dispatchable Asset Related Demand, or Demand Response Resource, the Resource must be placed in service and released for dispatch on or before December 31 for inclusion in the analysis for setting the zonal Forward Reserve requirements for the subsequent summer Forward Reserve Procurement Period or on or before April 30 for inclusion in the analysis for setting the zonal Forward Reserve requirements for the subsequent winter Forward Reserve Procurement Period. For the deactivation or retirement of a Generator Asset, Dispatchable Asset Related Demand or Demand Response Resource, the Resource must have been removed from service on or before January 31 for inclusion in the analysis for setting the zonal Forward Reserve requirements for the subsequent summer

Forward Reserve Procurement Period or on or before May 31 for inclusion in the analysis for setting the zonal Forward Reserve requirements for the subsequent winter Forward Reserve Procurement Period.

The modified historical data set will be composed of actual data used in the operation of the reconfigured system and historical (pre-reconfiguration) data adjusted for the impact of the system reconfiguration. Pre-reconfiguration data will be revised by substituting values from the historical data set that are no longer valid with corresponding values used in the operation of the reconfigured system.

The zonal Forward Reserve requirements will be recalculated using the modified historical data set until the rolling two-year historical data set reflects a common system configuration.

III.9.3 Forward Reserve Auction Offers.

Forward Reserve Auction Offers for TMNSR and TMOR shall be (a) made on a $/MW-month basis, (b) made on a Reserve Zone specific basis, (c) made on a non-Resource specific basis and (d) shall be less than or equal to the Forward Reserve Offer Cap. Forward Reserve Auction Offers shall be submitted to the ISO by Market Participants. The Market Participants are responsible for complying with the requirements of this Section III.9 if the Forward Reserve Auction Offer is accepted.

III.9.4 Forward Reserve Auction Clearing and Forward Reserve Clearing Prices.

The Forward Reserve Auction shall simultaneously clear Forward Reserve Auction Offers to meet the Forward Reserve requirements for the system and each Reserve Zone using a mathematical programming algorithm. The objective of the mathematical programming based Forward Reserve Auction clearing is to minimize the total cost of Forward Reserve procured to meet the Forward Reserve requirements. The Forward Reserve Clearing Price for each Reserve Zone will reflect the cost to serve the next increment of reserve in that Reserve Zone based on the submitted offers. The Forward Reserve Auction algorithm substitutes higher quality TMNSR for lower quality TMOR to meet system or Reserve Zone Forward Reserve requirements when it is economical to do so provided that no constraints are violated.

The Forward Reserve Auction algorithm shall also utilize excess Forward Reserve in one Reserve Zone to meet the Forward Reserve requirements of another Reserve Zone or the system provided that the Forward Reserve can be delivered such that no constraints are violated. In addition, the Forward Reserve Auction shall apply price cascading such that the Forward Reserve Clearing Price for TMOR in a Reserve Zone is always less than or equal to the Forward Reserve Clearing Price for TMNSR in that Reserve Zone. If there is insufficient supply to meet the Forward Reserve requirements for a Reserve Zone, the Forward Reserve Clearing Price for that Reserve Zone will be set to the Forward Reserve Offer Cap.

III.9.4.1 Forward Reserve Clearing Price and Forward Reserve Obligation Publication and Correction.

Market Participants with cleared Forward Reserve Auction Offers will receive a Forward Reserve Obligation for each Reserve Zone, as applicable, that is equal to the amount of Forward Reserve megawatts cleared for that Market Participant adjusted for internal bilateral transactions that transfer Forward Reserve Obligations.

(a) Within five business days after the close of the Forward Reserve Auctions, the ISO shall post Forward Reserve Clearing Prices and Forward Reserve Obligations, which shall be final as posted, not subject to correction or other adjustment, and used for the purposes of settlement, except as provided in subsections (c) and (d). The permissibility of correction of errors in sections of Market Rule 1 relating to settlement and billing processes shall not apply to Forward Reserve Clearing Prices and Forward Reserve Obligations deemed final pursuant to this Section III.9.4.1.

(b) Before posting the final Forward Reserve Clearing Prices and Forward Reserve Obligations, the ISO shall make a good faith effort when clearing those markets to discover and correct any errors that may occur due to database, software or similar errors of the ISO or its systems before publishing the final prices awarded.

(c) If the ISO determines based on reasonable belief that there may be one or more errors in the final Forward Reserve Clearing Prices and Forward Reserve Obligations or if no Forward Reserve Clearing Prices and Forward Reserve Obligations 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 11:59 p.m. of the third business day following the posting deadline specified in subsection (a), a notice that the Forward Reserve Clearing Prices and Forward Reserve Obligations are provisional and subject to correction or unavailable for initial publishing. The ISO shall confirm within three business days of posting a notice pursuant to this subsection whether there was an error in the Forward Reserve Clearing Prices and Forward Reserve Obligations and shall post a notice stating its findings.

(d) Within three business days after posting an initial notice pursuant to subsection (c); the ISO shall either: (1) publish final or corrected Forward Reserve Clearing Prices and Forward Reserve Obligations, or: (2) in the event that the ISO is unable to calculate and post final or corrected Forward Reserve Clearing Prices and Forward Reserve Obligations due to exigent circumstances not contemplated in this market rule, make an emergency filing with the Commission detailing the exigent circumstance which will not allow final Forward Reserve Clearing Prices and Forward Reserve Obligations to be calculated and posted, along with a proposed resolution including a timeline to post final prices.

III.9.5 Forward Reserve Resources

III.9.5.1 Assignment of Forward Reserve MWs to Forward Reserve Resources.

(a) Prior to the close of the Re-Offer Period for each Operating Day of the Forward Reserve Procurement Period, Market Participants must convert their Forward Reserve Obligations into Resource-specific obligations by assigning Forward Reserve MWs to specific eligible Forward Reserve Resources, in accordance with procedures set forth in the ISO New England Manuals. The assignment of Forward Reserve MWs to a Forward Reserve Resource must be performed by the Lead Market Participant for the Resource.

(b) A Market Participant with a Forward Reserve Obligation must have an Ownership Share in a Forward Reserve Resource that is a Generator Asset or a Dispatchable Asset Related Demand, or be the Lead Market Participant of a Forward Reserve Resource that is a Demand Response Resource, in order to assign Forward Reserve MWs to that Forward Reserve Resource to fulfill that Market Participant's Forward Reserve Obligation. If more than one Market Participant has an Ownership Share in a Forward Reserve Resource, the Forward Reserve MWs assigned to that Resource will be allocated pro-rata to Market Participants by Ownership Share.

III.9.5.2 Forward Reserve Resource Eligibility Requirements.

(a) Forward Reserve Resources are Resources that have been assigned by Market Participants to meet their Forward Reserve Obligations. To be eligible as a Forward Reserve Resource, a Resource must satisfy the following criteria:

(i) If the Generator Asset is off-line, it must be a Fast Start Generator and have an audited CLAIM10 or CLAIM30 established pursuant to Section III.9.5.3;

(ii) If the Resource is a Demand Response Resource which has not been dispatched, it must be a Fast Start Demand Response Resource and have an audited CLAIM10 or CLAIM30 established pursuant to Section III.9.5.3;

(iii) If the Generator Asset or Dispatchable Asset Related Demand is expected to be on-line, or, for a Demand Response Resource, has been dispatched, during a Forward Reserve Delivery Period, it must be able to produce the energy or demand reduction equivalent to its assigned Forward Reserve Obligation within the timeframe of the assigned Forward Reserve Obligation when operating within its dispatch range;

(iv) Any portion of the Resource to which a Forward Reserve Obligation has been assigned that is without a Capacity Supply Obligation must not have been offered to support an External Transaction sale during the Operating Day for which it has been assigned;

(v) The Resource must be capable of receiving and responding to electronic Dispatch Instructions;

(vi) The Resource must follow Dispatch Instructions during the Operating Day. The Resource must meet the technical requirements associated with the provision of Operating Reserve as specified in ISO New England Operating Procedure No. 14;

(vii) The portion of the Resource that is assigned a Forward Reserve Obligation for any portion of an Operating Day must be eligible to provide Operating Reserve in accordance with the provisions of Section III.1.7.19;

(viii) The portion of the Resource to which a Forward Reserve Obligation has been assigned must be offered into the Real-Time Energy Market in accordance with the provisions of either Section III.13.6.1.1.2 or Section III.13.6.1.5.2.

(b) External Resources will be permitted to participate in the Forward Reserve Market when the respective Control Areas implement the technology and processes necessary to support recognition of Operating Reserves from external Resources.

III.9.5.3 Resource CLAIM10 and CLAIM30.

III.9.5.3.1 Calculating Resource CLAIM10 and CLAIM30.

1. The CLAIM10 or CLAIM30 of a Resource shall equal:
   (a) the maximum output or demand-reduction level reached, including the level reached during a CLAIM10 or CLAIM30 audit, measured at the 10 minute or 30 minute point from the Resource's receipt of an initial electronic startup Dispatch Instruction during the current Summer Capability Period or Winter Capability Period or the preceding Summer Capability Period or Winter Capability Period (as applicable to the current capability period), subject to the conditions in Section III.9.5.3.1.2 below;

   (b) multiplied by the Resource's then effective CLAIM10 or CLAIM30 performance factor established pursuant to Section III.9.5.3.3.

2. The value in Section III.9.5.3.1.1(a) is subject to the following additional conditions:
   (a) The value shall not include any dispatch in which the Resource becomes unavailable within 60 minutes following the receipt of the initial Dispatch Instruction;

   (b) If the maximum output or demand-reduction level reached, as measured at the 10 minute or 30 minute point from the initial Dispatch Instruction, is greater than the highest Desired Dispatch Point issued for the Resource for that 10 minute or 30 minute period, the value shall be capped at the highest Desired Dispatch Point.

3. A Resource's CLAIM10 shall be no greater than the Resource's CLAIM30.

4. The CLAIM10 or CLAIM30 of a Resource shall be calculated and distributed to the Market Participant weekly and shall become effective at 0001 of the Monday following the distribution.

5. The values described in Sections III.9.5.3.1(1)(a) and (b) shall not include any dispatch where:

   a) The Resource is dispatched at the request of the Market Participant or Designated Entity and the dispatch was not related to an Establish Claimed Capability Audit request made pursuant to Section III.1.5.1.2, a Seasonal DR Audit request made pursuant to Section III.1.5.1.3.1, or a CLAIM10 or CLAIM30 audit request made pursuant to Section III.9.5.3.2;

b) The prices associated with the Blocks to Economic Min for the Real-Time dispatch of the Resource are less than or equal to zero;

c) For Generator Assets, the ratio of (i) the sum of the applicable Start-Up Fee, No-Load Fee for one hour, and energy cost to Economic Min used in the Real-Time dispatch of the Resource in the Operating Day to (ii) the maximum total hourly Start-Up Fee, No-Load Fee for one hour, and energy cost to Economic Min submitted for the Resource for use in the Day-Ahead Energy Market for the same Operating Day, is below a threshold value determined by the ISO. If the Market Participant believes that the ratio is below the ISO-determined threshold value due to (i) differences in cost between Gas Days, or (ii) a reduction in the cost of gas within the Operating Day reflected in the offers submitted for the Resource during the remainder of the Operating Day, then the Market Participant may request that the ISO evaluate whether the dispatch may be included; or

d) For Demand Response Resources, the ratio of (i) the sum of the applicable Interruption Cost and the demand reduction cost to Minimum Reduction used in the Real-Time dispatch of the Demand Response Resource in the Operating Day to (ii) the maximum total hourly Interruption Cost and demand reduction cost to Minimum Reduction submitted for the Demand Response Resource for use in the Day-Ahead Energy Market for the same Operating Day, is below a threshold determined by the ISO. If the Market Participant believes that the ratio is below the ISO-determined threshold value due to differences in cost between Gas Days, then the Market Participant may request that the ISO evaluate whether the dispatch may be included.

6. A Demand Response Resource's CLAIM10 and CLAIM30 on June 1, 2018 and October 1, 2018 shall be as follows:

a) On June 1, 2018 and October 1, 2018, the CLAIM10 of a Demand Response Resource shall equal zero.

b) On June 1, 2018, the CLAIM30 of a Demand Response Resource with one or more Demand Response Assets that were 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) shall equal the sum of the 30 minute capabilities demonstrated by each such Demand Response Asset in a valid audit conducted during the Summer Capability Period beginning June 1, 2017. Such a CLAIM30 shall remain valid until the earlier of: (i) July 2, 2018, or (ii) receipt by the Demand Response Resource of an electronic startup Dispatch Instruction that permits the calculation of a CLAIM30 pursuant to Section III.9.5.3.1(1). If the Demand Response Resource does not receive such an electronic startup Dispatch Instruction on or before June 27, 2018, its CLAIM30 shall be set to zero on July 2, 2018.

c) On October 1, 2018, the CLAIM30 of a Demand Response Resource with one or more Demand Response Assets that were 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) shall equal the sum of the 30 minute capabilities demonstrated by each such Demand Response Asset in a valid audit conducted during the Winter Capability Period beginning October 1, 2017. Such a CLAIM30 shall remain valid until the earlier of: (i) October 29, 2018, or (ii) receipt by the Demand Response Resource of an electronic startup Dispatch Instruction that permits the calculation of a CLAIM30 pursuant to Section III.9.5.3.1(1). If the Demand Response Resource does not receive such an electronic startup Dispatch Instruction on or before October 24, 2018, its CLAIM30 shall be set to zero on October 29, 2018.

III.9.5.3.2 CLAIM10 and CLAIM30 Audits.

(a) **General.** A Market Participant may request a CLAIM10 or CLAIM30 audit specifying the requested output or demand-reduction level that the Resource will attempt to reach in 10 or 30 minutes. A Market Participant may not request more than one audit per week for the same Resource, provided that, if the Resource fails to start, trips offline, or becomes unavailable to provide a demand reduction during the audit, then the Market Participant may request another audit in the same week. The ISO, at its sole discretion, may allow a Market Participant to request more than one audit per week for the same Resource if the Resource historically has multiple startup dispatches included in its CLAIM10 or CLAIM30 calculations per week. A Market Participant may cancel an audit request prior to issuance of the audit Dispatch Instruction.

(b) **CLAIM10 and CLAIM30 Audit Procedures.** The ISO will initiate a CLAIM10 or CLAIM30 audit by issuing an electronic Dispatch Instruction without providing prior notice to the Market Participant. The ISO will normally perform the audit, at any time between 0800 and 2200 on a non-NERC-holiday weekday, within five Business Days of receipt of the audit request or will advise the Market Participant if it will be unable to initiate the audit during the five Business Day period. The Resource’s CLAIM10 or CLAIM30 audit value shall be the Resource’s output or demand-reduction level reached at the 10 minute or 30 minute point after the receipt of the initial startup Dispatch Instruction.

III.9.5.3.3 CLAIM10 and CLAIM30 Performance Factors.

A Resource’s CLAIM10 or CLAIM30 performance factor shall be established based upon the 10 most recent ISO-issued initial electronic startup Dispatch Instructions as described below. Dispatches greater than three years old shall not be used for the performance factor calculation. Resource performance factors will be calculated on a weekly basis.

(a) A Resource’s performance factor is calculated as:

$$performance\ factor = \frac{\sum_{n=1}^{10}\left(\frac{resource\ output\ or\ demand\ reduction\ at\ 10\ or\ 30\ minutes_n\ (MW)}{resource\ target\ value_n\ (MW)} * n\right)}{\sum_{n=1}^{10} n}$$

Where:

n is a value between 1 and 10, 1 representing the least recent dispatch signal, 10 representing the most recent dispatch signal;

the Resource output or demand reduction is measured at the 10 minute or 30 minute point from receipt of the initial startup Dispatch Instruction;

the Resource target value is the lesser of: (i) the minimum electronic Desired Dispatch Point sent to the Resource during the 10 minute or 30 minute period or the Resource’s Economic Minimum Limit or Minimum Reduction, whichever is greater or (ii) the Resource’s CLAIM10 or CLAIM30 or (iii) the Resource’s Offered CLAIM10 or Offered CLAIM30.

(b) For purposes of the performance factor calculation, the following conditions apply:

(i) For each CLAIM10 or CLAIM30 audit, the Resource’s target value shall be set to the Resource’s output or demand reduction at 10 or 30 minutes.

(ii) In the event the Resource has not had 10 electronic startup dispatches within the last three years, the “n” term in the performance factor calculation will be based on the number of startup dispatches that took place in the last three years, with the most recent dispatch having a weight of 10 and with the weighting decreasing by 1 for each previous startup dispatch.

(iii) If a Resource's output or demand reduction at 10 or 30 minutes is greater than the Resource's target value, then the Resource target value shall be set to the Resource output at 10 or 30 minutes.

(iv) A dispatch shall not be utilized in the performance factor calculation if a Resource starts and subsequently performs a normal shut down or ceases its demand reduction, in response to a Dispatch Instruction to shut down or, for a Demand Response Resource, in response to a Dispatch Instruction to cease its demand reduction, within the 10 or 30 minute period following the initial electronic startup Dispatch Instruction.

(v) Resource output or demand reduction at 10 or 30 minutes shall equal zero if the Resource becomes unavailable for dispatch within the 60 minute period following the initial electronic startup Dispatch Instruction.

III.9.5.3.4 Performance Factor Cure.

In the event a Resource either (a) is unable to reach at least 60% of the Resource target level, as reflected in the Dispatch Instruction issued for the Resource, either five times in a row or seven out of 10 times, as a result of a chronic operational problem with the Resource or (b) undergoes a major overhaul scheduled and performed during a planned outage that was approved in the ISO's annual maintenance scheduling process or during a scheduled curtailment pursuant to Section III.8.3, a Market Participant may submit a restoration plan to the ISO to restore the Resource's CLAIM10 or CLAIM30 operational capability. Restoration plans submitted because of a Resource's inability to reach its target output or demand reduction shall indicate the specific nature of the problem, the steps to be taken to remedy the problem, and the timeline for completing the restoration. Restoration plans submitted for a major overhaul shall explain the actions taken during the planned outage or scheduled curtailment that would result in the increase of the Resource's CLAIM10 or CLAIM30. The ISO shall accept restoration plans that, upon review, indicate a reasonable likelihood of success in remedying the identified problem or, for a major overhaul, increasing the Resource's CLAIM10 or CLAIM30. Upon completion of the restoration, the Market Participant shall request a CLAIM10 or CLAIM30 audit of the Resource, using the procedures in Section III.9.5.3.2. Following the audit, the Resource's Performance Factor shall be set to 1.0, with all dispatches prior to the audit removed from the performance factor calculation.

III.9.6 Delivery of Reserve.

III.9.6.1 Dispatch and Energy Bidding of Reserve.

Forward Reserve shall be delivered by Forward Reserve Resources that are Generator Assets or Dispatchable Asset Related Demand for an hour by offering the capability into the Real-Time Energy Market by submitting Supply Offers and Demand Bids no later than 30 minutes prior to the start of the operating hour at or above the Forward Reserve Threshold Price for the Operating Day. Day-Ahead Energy Market Supply Offers and Demand Bids for Resources to which Forward Reserve Obligations have been assigned will be used in the Real-Time Energy Market for the associated Operating Day, even if the Supply Offers do not clear the Day-Ahead Energy Market, unless superseded by a more recent Supply Offer or Demand Bid submitted no later than 30 minutes prior to the start of the operating hour. A Market Participant is not required to submit a Supply Offer or Demand Bid into the Day-Ahead Energy Market for a Resource without a Capacity Supply Obligation in order for the Resource to be eligible to be a Forward Reserve Resource. The Forward Reserve Threshold Prices shall be set in accordance with the ISO New England Manuals so that Forward Reserve Resource capability has (a) a low probability of being dispatched for energy and (b) a high probability of being held for reserve purposes.

Forward Reserve shall be delivered by Forward Reserve Resources that are Demand Response Resources for an hour by offering the capability into the Real-Time Energy Market by submitting Demand Reduction Offers no later than the close of the Re-Offer Period at or above the Forward Reserve Threshold Price for the Operating Day.

Forward Reserve Resources are scheduled and operated in accordance with Section III.1 of Market Rule 1; no distinction is made due to their status as Forward Reserve Resources. Forward Reserve Resources are eligible to set the Locational Marginal Price in accordance with Section III.2 of Market Rule 1.

III.9.6.2 Forward Reserve Threshold Prices.

The formula for determining the Forward Reserve Threshold Prices shall be fixed for the duration of the Forward Reserve Procurement Period. The ISO will reevaluate the Forward Reserve Threshold Price level for successive Forward Reserve Auctions on the basis of experience, expected operating conditions and other relevant information.

Forward Reserve Threshold Price: is calculated as the Forward Reserve Heat Rate multiplied by the daily Forward Reserve Fuel Index.

<u>Forward Reserve Heat Rate</u>: shall be fixed for the duration of the Forward Reserve Procurement Period and announced in the announcement for the Forward Reserve Auction. New Forward Reserve Heat Rates shall be specified for successive auctions, and shall be calculated as follows:

(a) For each of the five most recently completed Summer Capability Periods or Winter Capability Periods (as applicable to the Forward Reserve Procurement Period), for each on-peak hour, the ISO shall calculate an implied heat rate, expressed in Btu/kWh, by dividing the hour's Hub Price by the lower of the applicable natural gas or heating oil price index.

(b) All resulting hourly implied heat rates above 45,000 Btu/kWh shall be excluded, and the remaining values shall be listed in order from high to low.

(c) The Forward Reserve Heat Rate for the Forward Reserve Procurement Period shall be the lesser of: (i) the heat rate that occurs at the 97.5th percentile of the list described in subsection (b) above; or (ii) 21,999 Btu/kWh.

<u>Forward Reserve Fuel Index:</u> is a daily fuel index, or combination of daily indices, applicable to the New England Control Area and specified in the announcement of the Forward Reserve Auction.

III.9.6.3 Monitoring of Forward Reserve Resources.

In accordance with Section III.A.13.4, 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 Participant in accordance with Section III.A.3. 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.

III.9.6.4 Forward Reserve Qualifying Megawatts.

(a) <u>Generator Assets and Dispatchable Asset Related Demands</u> – Qualifying megawatts for Generator Assets and Dispatchable Asset Related Demands are calculated separately on an hourly basis for Forward Reserve Resources supplying Forward Reserve from an off-line state and Forward Reserve Resources supplying Forward Reserve from an on-line state as follows:

Off-line qualifying megawatts. Off-line qualifying megawatts are the amount of a Generator Asset's capability equal to or below the Economic Maximum Limit for an off-line Forward Reserve Resource offered at or above the Forward Reserve Threshold Price. The Generator Asset must satisfy this requirement in the Real-Time Energy Market. In the case of off-line Forward Reserve Resources, the calculation for Forward Reserve Qualifying Megawatts shall include both the energy Supply Offer and a pro-rated amount of Start-Up Fees and No-Load Fees as defined below. The off-line qualifying megawatts of a Dispatchable Asset Related Demand are zero.

An off-line Forward Reserve Resource must offer its capability so that the following holds:

$$\frac{StartUp}{EcoMax \times 1\ hour} + \frac{NoLoad}{EcoMax} + Energy\ Offer_i \geq ForwardReserveThresholdPrice$$

where:

StartUp = cold Start-Up Fee.

NoLoad = No-Load Fee.

EnergyOffer$_i$ = the Energy offer price for Energy offer block $_i$.

EcoMax = Economic Maximum Limit.

On-line qualifying megawatts: is the capability that is less than or equal to the Economic Maximum Limit and above the Economic Minimum Limit that is offered at or above the applicable Forward Reserve Threshold Price by an on-line Generator Asset or, is the capability that is less than or equal to the Maximum Consumption Limit and greater than the Minimum Consumption Limit offered at or above the applicable Forward Reserve Threshold Price for a Dispatchable Asset Related Demand. The Forward Reserve Resource must satisfy this requirement in the Real-Time Energy Market. For an on-line Generator Asset that has been assigned to meet a Forward Reserve Obligation and has not cleared in the Day-Ahead Energy Market and is operating in a delivery hour as the result of an ISO commitment for VAR or local second contingency protection, the on-line qualifying megawatts shall be zero.

(b) **Demand Response Resources** – Qualifying megawatts for Demand Response Resources supplying Forward Reserve are calculated separately on an hourly basis for Demand Response Resources that have not been dispatched and Demand Response Resources that have been dispatched as follows:

Qualifying megawatts for a Demand Response Resource that has not been dispatched: is the amount of capability equal to or below the Maximum Reduction for the Demand Response Resource offered at or above the Forward Reserve Threshold Price. The Demand Response Resource must satisfy this requirement in the Real-Time Energy Market. In the case of Demand Response Resources that have not been dispatched, the calculation for Forward Reserve Qualifying Megawatts shall include both the Demand Reduction Offer price and a pro-rated amount of the Interruption Cost as defined below.

A Demand Response Resource that has not been dispatched must offer its capability so that the following holds:

–

where:

Interruption Cost = Interruption Cost.

EnergyOffer$_i$ = Demand Reduction Offer price for Energy offer block $_i$.

Max Red = Maximum Reduction x 1 hour.

Qualifying megawatts for a Demand Response Resource which has been dispatched: is the capability that is less than or equal to the Maximum Reduction and greater than the Minimum Reduction that is offered at or above the applicable Forward Reserve Threshold Price for the Demand Response Resource. The Demand Response Resource must satisfy this requirement in the Real-Time Energy Market. For a Demand Response Resource which has been dispatched, has been assigned to meet a Forward Reserve Obligation, has not cleared in the Day-Ahead Energy Market, and is operating in a delivery hour as the result of an ISO commitment for local second contingency protection, the qualifying megawatts shall be zero.

III.9.6.5 Delivery Accounting.

Forward Reserve Delivered Megawatts are the quantity of Forward Reserve delivered in each hour of the Real-Time Energy Market to each Reserve Zone and is calculated as follows.

(a) Forward Reserve Delivered Megawatts for an off-line Generator Asset are calculated in megawatts for each hour of the Real-Time Energy Market for each Reserve Zone as the minimum of:

(i) the amount, in MW, of Forward Reserve that the off-line Generator Asset can provide, based upon CLAIM10 and CLAIM30 provided in the Generator Asset's Real-Time Supply Offer,

(ii) Forward Reserve Assigned Megawatts, or

(iii) Forward Reserve Qualifying Megawatts for that Resource (MW offered at or above the applicable Forward Reserve Threshold Price per Section III.9.6.2), less any previously accounted for Forward Reserve Delivered Megawatts for that Resource.

(b) Forward Reserve Delivered Megawatts for an on-line Generator Asset are calculated in megawatts for each hour for each Reserve Zone as the minimum of:

(i) 10 or 30 times the MW/minute ramp rate of the on-line Generator Asset, as applicable,

(ii) Forward Reserve Assigned Megawatts, or

(iii) Forward Reserve Qualifying Megawatts for that Resource (MW offered at or above the applicable Forward Reserve Threshold Price per Section III.9.6.2)

less any previously accounted for Forward Reserve Delivered Megawatts for that Resource.

(c) Forward Reserve Delivered Megawatts for an on-line Dispatchable Asset Related Demand are calculated for each hour of the Real-Time Energy Market for each Reserve Zone as the minimum of:

(i) 10 or 30 times the MW/minute ramp rate of the Resource, as applicable,

(ii) Forward Reserve Assigned Megawatts, or

(iii) Forward Reserve Qualifying Megawatts for that Resource (MW offered at or above the applicable Forward Reserve Threshold Price per Section III.9.6.2),

less any previously accounted for Forward Reserve Delivered Megawatts for that Resource.

(d) A Forward Reserve Resource's hourly Forward Reserve Delivered Megawatts for each Reserve Zone is calculated as the sum of the Market Participant's Resource specific hourly Forward Reserve Delivered Megawatts for each Reserve Zone.

(e) Resource specific Forward Reserve Delivered Megawatts for TMNSR within a Reserve Zone will be applied first to a Market Participant's higher value Forward Reserve Obligation for TMNSR in that Reserve Zone. Any surplus Forward Reserve Delivered Megawatts for TMNSR in that Reserve Zone will be applied to meet the Market Participant's Forward Reserve Obligation for TMOR in that Reserve Zone. Forward Reserve Delivered Megawatts remaining within that Reserve Zone after the Market Participant's Forward Reserve Obligation for that Reserve Zone have been met is available to be applied to the Market Participant's Forward Reserve Obligations in other Reserve Zones provided that the Forward Reserve Delivered Megawatts can be delivered to the other Reserve Zones.

(f) Forward Reserve Delivered Megawatts for a Demand Response Resource which has not been dispatched are calculated for each hour of the Real-Time Energy Market for each Reserve Zone as the minimum of:

(i) the amount of Forward Reserve that the Resource can provide, based upon CLAIM10 and CLAIM30 provided in the Demand Response Resource's Demand Reduction Offer,

(ii) Forward Reserve Assigned Megawatts, or

(iii) Forward Reserve Qualifying Megawatts for that Resource (energy at or above the applicable Forward Reserve Threshold Price per Section III.9.6.2), less any previously accounted for Forward Reserve Delivered Megawatts for that Resource.

(g) Forward Reserve Delivered Megawatts for a Demand Response Resource which has been dispatched are calculated for each hour for each Reserve Zone as the minimum of:

(i) 10 or 30 times the MW/minute Demand Response Resource Ramp Rate of that Resource, as applicable,

(ii) Forward Reserve Assigned Megawatts, or

(iii) Forward Reserve Qualifying Megawatts for that Resource (MW offered at or above the applicable Forward Reserve Threshold Price per Section III.9.6.2)

less any previously accounted for Forward Reserve Delivered Megawatts for that Resource.

(h) In determining Forward Reserve Delivered Megawatts for Demand Response Resources the portion of the Forward Reserve Delivered Megawatts not associated with Net Supply shall be increased by average avoided peak distribution losses, limited as described below.

(i) The ISO will assume that Demand Response Resources first reduce their net load from the electricity system before providing additional Net Supply.

(ii) The portion of the Forward Reserve Delivered Megawatts not associated with Net Supply shall be the lesser of: (1) Forward Reserve Delivered Megawatts and (2) the amount of load that the Demand Response Resource can reduce from the electric system based on the net load of its constituent Demand Response Assets.

(iii) Any remaining Forward Reserve Delivered Megawatts in excess of the portion not associated with Net Supply will be capped at the remaining Net Supply Capability of the Demand Response Resource.

III.9.7 Consequences of Delivery Failure.

III.9.7.1 Real-Time Failure-to-Reserve.

A Real-Time Forward Reserve Failure-to-Reserve 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.

(a) Forward Reserve Failure-to-Reserve Megawatts:

(i) A Market Participant's Forward Reserve Failure-to-Reserve Megawatts for TMNSR for a Reserve Zone is defined as, for each hour, the amount that is the maximum of the following values:

(1) Market Participant Forward Reserve Obligation for TMNSR for that Reserve Zone minus the Market Participant's Forward Reserve Delivered Megawatts for TMNSR for that Reserve Zone; and

(2) Zero.

(ii) A Market Participant's Forward Reserve Failure-to-Reserve Megawatts for TMOR for a Reserve Zone is defined as, for each hour, the amount that is the maximum of the following values:

(1) Market Participant Forward Reserve Obligation for TMOR for that Reserve Zone minus Market Participant's Forward Reserve Delivered Megawatts for TMOR for that Reserve Zone; and

(2) Zero.

(b) Forward Reserve Failure-to-Reserve Penalties: A Market Participant's Forward Reserve Failure-to-Reserve Penalty for a Reserve Zone in an hour is defined as:

(i) Forward Reserve Failure-to-Reserve Penalty for TMNSR = Forward Reserve Failure-to-Reserve Penalty Rate multiplied by the Forward Reserve Failure-to-Reserve Megawatts for TMNSR; and

(ii) Forward Reserve Failure-to-Reserve Penalty for TMOR = Forward Reserve Failure-to-Reserve Penalty Rate multiplied by the Forward Reserve Failure-to-Reserve Megawatts for TMOR;

Where:

Forward Reserve Failure-to-Reserve Penalty Rate (calculated for each Forward Reserve product and for each Reserve Zone) = maximum of (1.5 multiplied by the Forward Reserve Payment Rate for the Forward Reserve product, the applicable Real-Time Reserve Clearing Price for the Forward Reserve product in the Reserve Zone minus the Forward Reserve Payment Rate for the Forward Reserve product)

III.9.7.2 Failure-to-Activate Penalties.

Market Participants are required to pay a Forward Reserve Failure-to-Activate Penalty for each Forward Reserve Resource that fails to activate its Forward Reserve capability. For Forward Reserve Resources:

- providing TMNSR, the Forward Reserve Failure-to-Activate Penalty is applied if a resource fails to activate in response to a Dispatch Instruction as part of the real-time contingency dispatch algorithm, or;
- providing TMOR, the Forward Reserve Failure-to-Activate Penalty is applied if a resource fails to activate in response to a Dispatch Instruction when the ten-minute reserve requirement is binding or violated in an approved UDS case.

If a Market Participant's Forward Reserve Resource fails to activate Forward Reserve, which determination shall be made in accordance with subsection (a), that Market Participant shall be required to pay a Forward Reserve Failure-to-Activate Penalty associated with that Resource pursuant to subsection (b):

(a) **Forward Reserve Failure-to-Activate Megawatts**:

(i) A Market Participant's Forward Reserve Failure-to-Activate Megawatts for TMNSR for a Resource is defined as, for each hour, the amount that is the lesser of the following values:

(1) Maximum of Forward Reserve Delivered Megawatts for TMNSR minus actual amount of TMNSR energy delivered during activation, or zero;

(2) Maximum of Target Activation Megawatts for TMNSR minus actual amount of TMNSR energy delivered during activation, or zero;

Where:

Target Activation Megawatts for TMNSR from off-line Forward Reserve Resources or Demand Response Resources that are not dispatched, which are subsequently dispatched as part of the real-time contingency dispatch algorithm is the lesser of: (i) the minimum electronic Desired

Dispatch Point sent to the Resource during the 10 minute period or the Resource's Economic Minimum Limit or Minimum Reduction, whichever is greater, (ii) the Resource's CLAIM10, and (iii) the Resource's Offered CLAIM10.

Target Activation Megawatts for TMNSR from on-line Forward Reserve Resources or Demand Response Resources that have been dispatched is as follows:

1. For Generator Assets, the lesser of: (i) the Resource's Manual Response Rate times 10 minutes, (ii) the Resource's Economic Maximum Limit minus the Resource's initial output at activation, and (iii) the minimum electronic Desired Dispatch Point sent to the Resource during the 10 minute period minus the Resource's initial output at activation.
2. For Storage DARDs, the Resource's initial consumption at activation minus the maximum electronic Desired Dispatch Point sent to the Resource during the 10 minute period.
3. For DARDs that are not Storage DARDs, the lesser of: (i) the Resource's Manual Response Rate times 10 minutes, (ii) Resource's initial consumption at activation minus the Resource's Minimum Consumption Limit, and (iii) the Resource's initial consumption at activation minus the maximum electronic Desired Dispatch Point sent to the Resource during the 10 minute period.
4. For Demand Response Resources, the lesser of: (i) the Resource's Demand Response Resource Ramp Rate times 10 minutes, (ii) the Resource's Maximum Reduction minus the Resource's initial demand reduction at activation, and (iii) the minimum electronic Desired Dispatch Point sent to the Resource during the 10 minute period minus the Resource's initial demand reduction at activation.

The actual amount of TMNSR energy delivered during activation is measured at the 10 minute point following receipt of the initial Dispatch Instruction. The actual amount of TMNSR energy delivered during activation is set to zero if the Resource becomes unavailable for dispatch within the 60 minute period following the receipt of the initial Dispatch Instruction.

(ii) A Market Participant's Forward Reserve Failure-to-Activate Megawatts for TMOR for a Resource is defined as, for each hour, the amount that is the lesser of the following values:

(1) Maximum of Forward Reserve Delivered Megawatts for TMOR plus Forward Reserve Delivered Megawatts for TMNSR minus Forward Reserve Failure-to-Activate Megawatts for TMNSR minus actual amount of TMOR energy delivered during activation, or zero;

(2) Maximum of Target Activation Megawatts for TMOR minus Forward Reserve Failure-to-Activate Megawatts for TMNSR minus actual amount of TMOR energy delivered during activation, or zero;

Where:

Target Activation Megawatts for TMOR from off-line Forward Reserve Resources or Demand Response Resources that are not dispatched is the lesser of: (i) the minimum electronic Desired Dispatch Point sent to the Resource during the 30 minute period or the Resource's Economic Minimum Limit or Minimum Reduction, whichever is greater or (ii) the Resource's CLAIM30, or; (iii) the Resource's Offered CLAIM30.

Target Activation Megawatts for TMOR from on-line Forward Reserve Resources or Demand Response Resources that have been dispatched is as follows:

1. For Generator Assets, the lesser of: (i) the Resource's Manual Response Rate times 30 minutes, (ii) the Resource's Economic Maximum Limit minus the Resource's initial output at activation, and (iii) the minimum electronic Desired Dispatch Point sent to the Resource during the 30 minute period minus the Resource's initial output at activation.
2. For Storage DARDs, the Resource's initial consumption at activation minus the maximum electronic Desired Dispatch Point sent to the Resource during the 30 minute period.
3. For DARDs that are not Storage DARDs, the lesser of: (i) the Resource's Manual Response Rate times 30 minutes, (ii) Resource's initial consumption at activation minus the Resource's Minimum Consumption Limit, and (iii) the Resource's initial consumption at activation minus the maximum electronic Desired Dispatch Point sent to the Resource during the 30 minute period.

4. For Demand Response Resources, the lesser of: (i) the Resource's Demand Response Resource Ramp Rate times 30 minutes, (ii) the Resource's Maximum Reduction minus the Resource's initial demand reduction at activation, and (iii) the minimum electronic Desired Dispatch Point sent to the Resource during the 30 minute period minus the Resource's initial demand reduction at activation.

The actual amount of TMOR energy delivered during activation is measured at the 30 minute point following receipt of the initial Dispatch Instruction. The actual amount of TMOR energy delivered during activation is set to zero if the Resource becomes unavailable for dispatch within the 60 minute period following the receipt of the initial Dispatch Instruction.

(iii) In determining the Target Activation Megawatts for Demand Response Resources, the portion of the Target Activation Megawatts not associated with Net Supply shall be increased by average avoided peak distribution losses. The portion of the Target Activation Megawatts not associated with Net Supply shall be calculated as the greater of: (1) the Target Activation Megawatts minus the amount of Net Supply that the Demand Response Resource produced during activation or (2) zero.

A Forward Reserve Resource that is a Fast Start Generator that fails to activate Forward Reserve through a failure to start, or a Forward Reserve Resource that is a Fast Start Demand Response Resource that fails to activate Forward Reserve through a failure to provide a demand reduction, shall have its Forward Reserve Delivered Megawatts set equal to zero in each subsequent hour in the applicable Forward Reserve Delivery Period until such time that the Market Participant notifies the ISO that the Forward Reserve Resource is capable of providing the Forward Reserve Delivered Megawatts.

(b) **Forward Reserve Failure-to-Activate Penalties:**

A Market Participant's Forward Reserve Failure-to-Activate Penalty for a Resource in an hour is defined as:

(i) Forward Reserve Failure-to-Activate Penalty for TMNSR = The sum of the Forward Reserve Payment Rate for TMNSR and the Forward Reserve Failure-to-Activate Penalty Rate multiplied by the Forward Reserve Failure-to-Activate Megawatts for TMNSR; and

(ii) Forward Reserve Failure-to-Activate Penalty for TMOR = The sum of the Forward Reserve Payment Rate for TMOR and the Forward Reserve Failure-to-Activate Penalty Rate multiplied by the Forward Reserve Failure-to-Activate Megawatts for TMOR;

Where:

Forward Reserve Failure-to-Activate Penalty Rate = Maximum of 2.25 multiplied by the Forward Reserve Payment Rate, or the applicable nodal LMP.

III.9.7.3 Known Performance Limitations.

The ISO may have reason to believe that a particular Forward Reserve Resource is frequently receiving, or may frequently receive, Forward Reserve payments for a portion or all of its capability that is not capable of activating the Forward Reserve Assigned Megawatts for TMNSR or the Forward Reserve Assigned Megawatts for TMOR. When the ISO believes there is such a limited Forward Reserve Resource, the ISO shall contact and confer with the affected Market Participant before taking any action.

(a) The ISO will, whenever practicable, contact the affected Market Participant of the Forward Reserve Resource to request an explanation of the relevant resource Offer Data;

(b) If the explanation, if available, considered together with other information available to the ISO, indicates to the satisfaction of the ISO that the questioned Forward Reserve payments are consistent with Forward Reserve Resource capabilities, no further action will be taken; and

(c) If no agreement is reached, or an acceptable explanation is not provided, the Market Participant may request a Resource performance audit. If the Forward Reserve Resource fails the performance audit or the Market Participant refuses to request a Resource performance audit, the ISO may take remedial action. Remedial actions may include, but are not limited to: (i) redeclaration, by the ISO, of any relevant operational Offer Data parameter, or (ii) removing the Resource or the relevant portion of the Resource's capability to provide Forward Reserve on a going-forward basis.

III.9.8 Forward Reserve Credits.

Payment for Forward Reserve is based upon a Market Participant's Final Forward Reserve Obligation and the applicable Forward Reserve Clearing Prices. The ISO shall calculate these credits on an hourly basis for each Reserve Zone as follows:

(a) Final Forward Reserve Obligations for TMNSR and TMOR for each Market Participant are calculated for each Reserve Zone for each hour as follows:

(i) Final Forward Reserve Obligation = minimum [Forward Reserve Obligation, Forward Reserve Delivered Megawatts]

(b) $FRACP_{Zone}$ is defined as the Forward Reserve Clearing Price for the relevant Reserve Zone, for TMNSR or TMOR, respectively;

(c) Market Participant Forward Reserve Credit for TMNSR=Final Forward Reserve Obligation for TMNSR multiplied by the applicable hourly Forward Reserve Payment Rate for TMNSR;

where,

the hourly Forward Reserve Payment Rate for TMNSR is equal to:

applicable monthly $FRACP_{Zone}$ for TMNSR divided by the number of hours in the month associated with the Forward Reserve Delivery Period.

(d) Market Participant Forward Reserve Credit for TMOR = Final Forward Reserve Obligation for TMOR multiplied by the applicable hourly Forward Reserve Payment Rate for TMOR;

where,

the hourly Forward Reserve Payment Rate for TMOR is equal to:

applicable monthly $FRACP_{Zone}$ for TMOR divided by the number of hours in the month associated with the Forward Reserve Delivery Period.

III.9.9 Forward Reserve Charges.

Forward Reserve Charges are allocated to each Market Participant in two steps. The first step allocates the Forward Reserve Credits associated with the procurement of reserves to meet the Forward Reserve requirement for the system. The second step, if necessary, allocates any remaining Forward Reserve Credits.

III.9.9.1 Forward Reserve Credits Associated with System Reserve Requirement.
The portion of Forward Reserve Credits associated with the procurement of the Forward Reserve requirement for the system is determined by simulating a Forward Reserve Auction using all submitted Forward Reserve Auction Offers to meet only the Forward Reserve Market minimum requirements for the New England Control Area pursuant to Section III.9.2.1. The simulated Forward Reserve Auction will clear offers pursuant to the methodology set forth in Section III.9.4 to calculate TMNSR and TMOR proxy system clearing prices. The TMNSR and TMOR proxy system clearing prices will reflect the cost to serve the next increment of reserve above the Forward Reserve Market minimum requirement for the New England Control Area.

For each hour, the total amount of Forward Reserve Credits associated with the procurement of the Forward Reserve requirement for the system is calculated as the lesser of:

(i) The TMNSR Forward Reserve Market minimum requirement for the New England Control Area pursuant to Section III.9.2.1 multiplied by the TMNSR proxy system clearing price, plus the TMOR Forward Reserve Market minimum requirement for the New England Control Area pursuant to Section III.9.2.1 multiplied by the TMOR proxy system clearing price and divided by the number of hours in the month associated with the Forward Reserve Delivery Period, or
(ii) Total Forward Reserve Credits for the New England Control Area as calculated pursuant to Section III.9.8.

III.9.9.2 Adjusting Forward Reserve Credits for System Requirement.
For each hour, the Forward Reserve Credits associated with the procurement of the Forward Reserve requirement for the system is reduced by:

(i) Any Forward Reserve Failure-to-Reserve Penalty or Forward Reserve Failure-to-Activate Penalty that occurs in the Rest of System or in a Load Zone that is ineligible to receive an allocation of Forward Reserve Credits pursuant to Section III.9.9.4.1, and
(ii) A prorated amount of any Forward Reserve Failure-to-Reserve Penalty or Forward Reserve Failure-to-Activate Penalty that occurs in a Load Zone that is eligible to receive an allocation of Forward Reserve Credits pursuant to Section III.9.9.4.1, where the prorated amount is calculated

based on the ratio of Forward Reserve Credits calculated in Section III.9.9.1 to the total Forward Reserve Credits.

III.9.9.3 Allocating Forward Reserve Credits for System Requirements.

For each hour, the Forward Reserve Credits associated with the procurement of the Forward Reserve requirements for the system as calculated pursuant to Section III.9.9.1, is reduced by any penalties calculated pursuant to Section III.9.9.2, and allocated on a pro rata basis using each Market Participant's share of Real-Time Load Obligation in each Load Zone (which includes the Market Participant's Real-Time Load Obligation associated with any Capacity Export Through Import Constrained Zone Transaction pursuant to Section III.1.10.7(f)(i) or with any FCA Cleared Export Transaction pursuant to Section III.1.10.7(f)(ii), reduced by that Market Participant's Reserve Quantity For Settlement associated with Dispatchable Asset Related Demands within that Load Zone.

III.9.9.4 Allocating Remaining Forward Reserve Credits.

For each hour, any Forward Reserve Credits not allocated pursuant to Section III.9.9.3 are allocated on a pro rata basis to each Market Participant's share of Real-Time Load Obligation in a Load Zone (which includes the Market Participant's Real-Time Load Obligation associated with any Capacity Export Through Import Constrained Zone Transaction pursuant to Section III.1.10.7(f)(i) or with any FCA Cleared Export Transaction pursuant to Section III.1.10.7(f)(ii), reduced by that Market Participant's Reserve Quantity For Settlement associated with Dispatchable Asset Related Demands within that Load Zone) that meets the criteria in Section III.9.9.4.1. The allocation for each Load Zone is based on the ratio of the Forward Reserve Credits cleared in the Respective Reserve Zone for the Forward Reserve Credits cleared in all Reserve Zones that meet the criteria in Section III.9.9.4.1, and is reduced by:

(i) A prorated amount of any Forward Reserve Failure-to-Reserve Penalties or Forward Reserve Failure-to-Activate Penalties that occur in a Load Zone eligible to receive an allocation of Forward Reserve Credits pursuant to Section III.9.9.4.1, where the prorated amount is calculated based on the ratio of the total Forward Reserve Credits less any Forward Reserve Credits calculated in Section III.9.9.1 to the total Forward Reserve Credits.

III.9.9.4.1 Allocation Criteria for Remaining Forward Reserve Credits.

If the following criteria are met, then a Market Participant with Real-Time Load Obligation in a Load Zone is eligible to receive any remaining Forward Reserve Credits not allocated pursuant to Section III.9.9.3.

(i) The Load Zone is encompassed in whole or in part in a Reserve Zone with a zonal Forward Reserve requirement greater than zero, and

(ii) The Forward Reserve Clearing Price of a Reserve Zone is higher than the Forward Reserve Clearing Price of the Rest of System.

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 or Day-Ahead Ancillary Services Offer for a Resource that is unjustifiably high and violates the economic withholding criteria set forth in Section III.A.5 or Section III.A.8 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.8, 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 and Day-Ahead Ancillary Services Offers in accordance with Section III.A.4 below for referral to the Commission.

(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 referral under Section III.A.19.

III.A.2.4.2. Conditions for the Imposition of Mitigation.

To achieve the foregoing purpose and objectives, mitigation measures are imposed pursuant to Sections III.A.5, III.A.8, III.A.10, and III.A.11 below.

III.A.2.4.3. Applicability.

Mitigation measures may be applied to Supply Offers, Increment Offers, Day-Ahead Ancillary Services 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***.

III.A.2.4.6. Correction of Mitigation.

If the Internal Market Monitor determines that there are one or more errors in the mitigation applied pursuant to Sections III.A.5 or III.A.8 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 Operating Day associated with the Supply Offer or Day-Ahead Ancillary Services Offer to which such mitigation applied. The ISO shall correct the error as part of the Data Reconciliation Process by applying the correct values to the relevant Supply Offer or Day-Ahead Ancillary Services 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.2.4.7. Delay of Day-Ahead Market Due to Mitigation Process.

The posting of the Day-Ahead Market results may be delayed if necessary for the completion of mitigation procedures.

III.A.3. Consultation Prior to Determination of Reference Levels for Physical and Financial Parameters of Resources and Benchmark Levels for Day-Ahead Ancillary Services Offers; 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 and Day-Ahead Ancillary Services Benchmark Levels under Section III.A.8.2 for that Market Participant**.** In order for the Internal Market Monitor to revise Reference Levels or Day-Ahead Ancillary Services Benchmark Levels, or treat an offer as not violating applicable conduct tests specified in Section III.A.5.5 or Section III.A.8.1.1 for an Operating Day or hour for which the offer is submitted, all cost data and other verifiable supporting 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 or Day-Ahead Ancillary Services Benchmark 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.

(a) 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(c), 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. If the Internal Market Monitor determines that there is an increased cost related to a Supply Offer, the Internal Market Monitor will either update the Reference Level or treat the offer as not violating applicable conduct tests specified in Section III.A.5.5 for the Operating Day for which the offer is submitted.

(b) 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(c), believes will cause the expected close-out costs or input costs associated with a Day-Ahead Ancillary Services Offer to exceed the level that would violate the conduct test specified in Section III.A.8.1.1 of this ***Appendix A***, the Market Participant may contact the Internal Market Monitor to provide an explanation of the increased costs. If the Internal Market Monitor determines that there is an increased cost related to a Day-Ahead Ancillary Services Offer, the Internal Market Monitor will either update one or both of the components of the Day-Ahead Ancillary Services Benchmark Level, as applicable, or treat the offer as not violating the conduct test specified in Section III.A.8.1.1 for the hour for which the offer is submitted.

(c) 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.

(d) Any request pursuant to this Section III.A.3.1 must be submitted to the Internal Market Monitor with all supporting cost data and other verifiable supporting information. In order for a request pursuant to this Section III.A.3.1 to be considered for the purposes of the Day-Ahead Market, the Market Participant must contact the Internal Market Monitor at least 30 minutes prior to the close of the Day-Ahead Market. In order for a request 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. A request 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.

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 and Day-Ahead Ancillary Services Benchmark Levels.

The Internal Market Monitor will make available to the Market Participant the Reference Levels and both components of the Day-Ahead Ancillary Services Benchmark Levels applicable to that Market Participant's Supply Offers and any Day-Ahead Ancillary Services Offers through the MUI. Updated Reference Levels and components of the Day-Ahead Ancillary Services Benchmark Levels will be made available whenever calculated. The Market Participant shall not modify such Reference Levels or the components of the Day-Ahead Ancillary Services Benchmark 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 and the Day-Ahead Ancillary Services Avoidable Input Cost for any associated Day-Ahead Ancillary Services Offers, 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 and the Day-Ahead Ancillary Services Avoidable Input Cost for any associated Day-Ahead Ancillary Services Offers. 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, and for any associated Day-Ahead Ancillary Services Offers entered in the Day-Ahead Ancillary Services Market. 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 and the Day-Ahead Ancillary Services Avoidable Input Cost for any associated Day-Ahead Ancillary Services Offers, the fuel price must be submitted prior to the applicable 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 and to cover an award consistent with any associated Day-Ahead Ancillary Services Offers, exclusive of resource-specific transportation costs. Modifications to Reference Levels or Day-Ahead Ancillary Services Avoidable Input Costs 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 and any Day-Ahead Ancillary Services Avoidable Input Cost or (2) the fuel price used by the Internal Market Monitor in calculating the Reference Levels for the Resource's Supply Offer and any Day-Ahead Ancillary Services Avoidable Input Cost 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 and any associated Day-Ahead Ancillary Services Offers, as of the time that the Supply Offer and any associated Day-Ahead Ancillary Services Offers were 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 and the components of Day-Ahead Ancillary Services Benchmark 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 Day-Ahead Ancillary Services 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;

(c) As applied to the Day-Ahead Ancillary Services Market, withholding that exceeds the greater of 20% or 100 MW of the total Day-Ahead Ancillary Services capability of a Market Participant's Resources; or

(d) 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 and Day-Ahead Ancillary Services capability 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 Sections III.A.5 or III.A.8, as appropriate.

III.A.5. Supply Offer 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. Supply Offer 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.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. Day-Ahead Ancillary Services Offer Mitigation.

Day-Ahead Ancillary Services Offers will be evaluated for economic withholding in the Day-Ahead Market and mitigated as described in this Section III.A.8.

III.A.8.1. Conduct and Impact Test.

III.A.8.1.1. Conduct Test.

A Day-Ahead Ancillary Services Offer price fails the conduct test for Day-Ahead Ancillary Services Offer mitigation in a given hour if such price exceeds an amount greater than the sum of (i) the greater of $2/MWh and 200% of the Day-Ahead Ancillary Services Expected Close-Out Component as described in Section III.A.8.2.1; and (ii) 150% of the Day-Ahead Ancillary Services Avoidable Input Cost as described in Section III.A.8.2.2.

III.A.8.1.2. Impact Test.

A Day-Ahead Ancillary Services Offer with a price that fails the conduct test for Day-Ahead Ancillary Services Offer mitigation shall be evaluated against the impact test for Day-Ahead Ancillary Services Offer mitigation. A Day-Ahead Ancillary Services Offer fails the impact test for Day-Ahead Ancillary Services Offer mitigation if there is an increase in any Day-Ahead Price, as calculated pursuant to Sections III.A.8.3 or III.A.8.4, in any hour of the Operating Day and such increase is greater than 150% of the median difference between:

(i) the threshold prices for failing the conduct test described in Section III.A.8.1.1 for all Day-Ahead Ancillary Services Offers in the hour of the Operating Day being evaluated; and

(ii) the Day-Ahead Ancillary Services Benchmark Levels as described in Section III.A.8.2 for all Day-Ahead Ancillary Services Offers in the hour of the Operating Day being evaluated.

III.A.8.1.3. Consequence of Failing Both Conduct and Impact Test.

If any Day-Ahead Ancillary Services Offer with a price that fails the Day-Ahead Ancillary Services Offer conduct test fails the impact test, then all Day-Ahead Ancillary Services Offer prices that failed the conduct test in the hour being evaluated shall be set to the applicable Day-Ahead Ancillary Services Benchmark Level.

III.A.8.2. Day-Ahead Ancillary Services Benchmark Levels.

A resource's Day-Ahead Ancillary Services Benchmark Level for the hour associated with the resource's Day-Ahead Ancillary Services Offer is the sum of the Day-Ahead Ancillary Services Expected Close-Out Component and the resource's Day-Ahead Ancillary Services Avoidable Input Cost for such hour.

III.A.8.2.1. Day-Ahead Ancillary Services Expected Close-Out Component.

The Day-Ahead Ancillary Services Expected Close-Out Component for a given hour is the lesser of the following:

(a) the expected value of the greater of (i) the hourly Real-Time Hub Price less the hourly Day-Ahead Ancillary Services Strike Price and (ii) zero; and

(b) the historical average of the estimated likelihood that the Real-Time Hub Price will be equal to or less than its expected value, multiplied by the greater of $100/MWh and the expected hourly Real-Time Hub Price.

III.A.8.2.2. Day-Ahead Ancillary Services Avoidable Input Cost.

For purposes of calculating Day-Ahead Ancillary Services Benchmark Levels and conducting the conduct test described in Section III.A.8.1.1, Day-Ahead Ancillary Services Avoidable Input Costs shall be determined as follows:

(a) For a Generator Asset with natural gas as its only fuel type, or a dual-fuel Generator Asset that has specified natural gas as its fuel type in its Supply Offer for the hour associated with the Day-Ahead Ancillary Services Offer, the Day-Ahead Ancillary Services Avoidable Input Cost shall be calculated based on the asset's average heat rate and the expected price of natural gas to cover the Day-Ahead Ancillary Services award, adjusted for the expected hourly Real-Time Hub Price.

(b) For an asset that is an Electric Storage Facility, the Day-Ahead Ancillary Services Avoidable Input Cost shall be calculated based on the expected cost of charging energy to cover the Day-Ahead Ancillary Services award, adjusted for the expected Real-Time revenue associated with that charged energy during the Operating Day.

(c) For asset types other than those described in subsections (a) and (b), the Day-Ahead Ancillary Services Avoidable Input Cost shall be zero.

(d) The Day-Ahead Ancillary Services Avoidable Input Cost shall in no case be less than zero.

III.A.8.2.3. Cost Information Provided Through Consultation.

In performing the Day-Ahead Ancillary Services Benchmark Level calculations in this Section III.A.8.2, the Internal Market Monitor shall take into account, as appropriate, information provided by the Market Participant through the consultation process described in Section III.A.3. The criteria enumerated in (a) through (e) of Section III.A.7.5 shall apply to estimates of costs when performing Day-Ahead Ancillary Services Benchmark Level calculations.

III.A.8.3. Calculation of Impact to the Day-Ahead Ancillary Services Market.

For the purpose of determining any increase in Day-Ahead Ancillary Services prices pursuant to Section III.A.8.1.2, the Day-Ahead Ancillary Service impact test shall calculate the difference between two Day-Ahead Ancillary Service prices for each product in each hour. The first price shall be calculated based on a run of the Day-Ahead Market using all Day-Ahead offers and bids as submitted. The second price shall be calculated based on a second run of the Day-Ahead Market substituting Day-Ahead Ancillary Services Benchmark Levels for the Day-Ahead Ancillary Services Offer prices that have failed the Day-Ahead Ancillary Services conduct test.

III.A.8.4. Calculation of Impact to the Day-Ahead Energy Market.

For the purpose of determining any increase in Day-Ahead energy prices pursuant to Section III.A.8.1.2, the Day-Ahead Ancillary Service impact test shall calculate the difference between two prices in each hour. The first price shall be the Hub Price calculated based on a run of the Day-Ahead Market using all Day-Ahead offers and bids as submitted. The second price shall be the Hub Price calculated based on a second run of the Day-Ahead Market substituting Day-Ahead Ancillary Services Benchmark Levels for the Day-Ahead Ancillary Services Offer prices that have failed the Day-Ahead Ancillary Services conduct test.

III.A.8.5. Duration of Day-Ahead Ancillary Services Offer Mitigation.

Any mitigation imposed on a Day-Ahead Ancillary Services Offer pursuant to this Section III.A.8 is in effect only for the hour in which the Day-Ahead Ancillary Services Offer has a price that fails the conduct test in Section III.A.8.1.1.

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.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.

(i) 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, variable operating and maintenance costs, or Day-Ahead Ancillary Services close-out or input 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(i)(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(i)(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.

(ii) 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 Market Participant also may submit a filing under Section III.A.15.2(i)(a) to seek recovery of opportunity costs within the Day-Ahead Market as a result of mitigation applied to the Resource's Day-Ahead Ancillary Services Offer under Section III.A.8. To recover such opportunity costs, the Market Participant must demonstrate as part of the filing requirements of Section III.A.15.2.1(iii) and (iv) that the original, unmitigated Day-Ahead Ancillary Services Offer reflected costs anticipated by the Market Participant at the time the offer was made. The filing must be made within the time period specified for a filing to address cost recovery under Section III.A.15.2(i)(a).

III.A.15.2.1. Contents of Filing.

Any Section 205 filing made pursuant to this section shall include: (i) the actual fuel, variable operating and maintenance costs, or Day-Ahead Ancillary Services close-out or input costs, or opportunity costs as described in Section III.A.15.2(iii), for the Resource for the applicable Operating Days, with supporting data and calculations for those costs; (ii) regarding actual costs, an explanation of (a) why such actual costs exceeded the Reference Level or Day-Ahead Ancillary Services Benchmark Level costs or, (b) in the absence of mitigation, why such actual costs, 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) sufficient documentation and information supporting the basis for the original offer at the time the offer was submitted; (iv) an explanation as to why the original offer should not have been mitigated to the applicable Reference Level or Benchmark Level, or in the absence of mitigation, why the Section III.A.15.1 request should not have been denied in whole or in part; (v) the Internal Market Monitor's written explanation provided pursuant to Section III.A.15.2.2; and (vi) 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), (ii), (iii), and (iv) 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 Competitiveness of Markets.

In furtherance of its function 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 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 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, as amended from time to time and available on the ISO's website. Consistent with the ISO New England Inc. Code of Conduct, at a minimum each such monitoring unit and its employees: (a) must have no material affiliation with any Market Participant or Affiliate, (b) must have no material financial interest in any Market Participant or Affiliate with potential exceptions for mutual funds and non-directed investments, (c) must not engage in any market transactions other than the performance of their duties hereunder, (d) may not accept anything of value from a Market Participant in excess of a *de minimis* amount, and (e) must advise a supervisor in the event they seek employment with a Market Participant, and must disqualify themselves from participating in any matter that would have an effect on the financial interest of the Market Participant.

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 certain New Capacity Resources in the Forward Capacity Auction as described in this Section III.A.21. The provisions of Sections III.A.21.1 and III.A.21.2 are not applicable to offers from New Import Capacity Resources that are subject to the pivotal supplier test in Section III.A.23.

III.A.21.1. Applicability of Buyer-Side Market Power Review.

The Internal Market Monitor will not conduct a buyer-side market power review of New Capacity Resources that meet the criteria described in this Section III.A.21.1.

III.A.21.1.1. Resources with Capacity Not Exceeding 5 MW.

A New Capacity Resource will not be subject to the Internal Market Monitor’s buyer-side market power review if the project’s expected auction capacity (in MW) at the time of the qualification process for the Forward Capacity Auction does not exceed 5 MW.

If a New Capacity Resource’s expected auction capacity exceeds 5 MW at the time of the qualification process for the Forward Capacity Auction, but the final FCA Qualified Capacity for the New Capacity Resource does not exceed 5 MW, an offer from the New Capacity Resource will not be mitigated pursuant to Section III.A.21.2.3, notwithstanding any buyer-side market power review that may have been conducted at the time of the qualification process.

III.A.21.1.2. Passive Demand Response Resources.

New Demand Capacity Resources that consist solely of On-Peak Demand Resources or Seasonal Peak Demand Resources will not be subject to the Internal Market Monitor's buyer-side market power review.

III.A.21.1.3. Resources Supported by a Qualifying Load-Side Relationship Certification.

New Capacity Resources will not be subject to the Internal Market Monitor's buyer-side market power review if the Project Sponsor submits a Load-Side Relationship Certification, as described in this Section III.A.21.1.3, demonstrating one of the following qualifying circumstances:

(a) the Project Sponsor and its Affiliates or partners, if any, are not load serving entities and are neither receiving nor expecting to receive any revenues from a load serving entity, state, or political subdivision of a state that relate to the development, operation, control, or output of the New Capacity Resource (excepting any revenues earned through an ISO-administered market); or

(b) the New Capacity Resource is a Sponsored Policy Resource.

For the purpose of this Section III.A.21, a load serving entity is any entity that has or is the type of entity that could acquire a Capacity Load Obligation in the Forward Capacity Market.

To demonstrate such circumstances, the Project Sponsor must include as part of the Load-Side Relationship Certification a sworn affidavit from an officer or principal for the Project Sponsor that includes factual detail sufficient to explain the qualifying circumstances. The Project Sponsor must submit the Load-Side Relationship Certification with the New Capacity Qualification Package, described in Section III.13.1.1.2.2, the New Demand Capacity Resource Qualification Package, described in Section III.13.1.4.1.1.2, or the New Distributed Energy Capacity Resource Qualification Package, described in Section III.13.1.4A.1.1.2. If the ISO is unable to determine from the Load-Side Relationship Certification that one of the qualifying circumstances exists, the New Capacity Resource's offer shall be subject to buyer-side market power review pursuant to Section III.A.21.2.

III.A.21.2. Review for the Exercise of Buyer-Side Market Power.

With the exception of New Capacity Resources that meet the criteria described in Section III.A.21.1, the Internal Market Monitor shall review requested lowest offer prices from New Capacity Resources, as described in Sections III.13.1.1.2.2.3(a), III.13.1.4.1.1.2.8(a), and III.13.1.4A.1.1.2.6(a), for the potential exercise of buyer-side market power following the process described in this Section III.A.21.2.

III.A.21.2.1. Conduct Test.

The Internal Market Monitor will perform a conduct test by reviewing the information described in Sections III.13.1.1.2.2.3(a), III.13.1.4.1.1.2.8(a), and III.13.1.4A.1.1.2.6(a) and determining a New Resource Offer Floor Price, as described in Section III.A.21.3, for the New Capacity Resource. A requested lowest offer price from a New Capacity Resource fails the conduct test if the Internal Market Monitor determines that the New Resource Offer Floor Price exceeds the requested lowest offer price.

III.A.21.2.2. Demonstration of Lack of Incentive to Exercise Buyer-Side Market Power.

If the Project Sponsor does not submit a Load-Side Relationship Certification (or the ISO rejects the Project Sponsor's Load-Side Relationship Certification) because the Project Sponsor is or is affiliated with a load serving entity or because the Project Sponsor receives or expects to receive revenues outside of ISO-administered markets from a load serving entity, the Project Sponsor is entitled to submit documentation and information as part of the New Capacity Qualification Package, the New Demand Capacity Resource Qualification Package, or New Distributed Energy Capacity Resource Qualification Package to demonstrate that, notwithstanding such a relationship with a load serving entity with regard to the New Capacity Resource, such load serving entity would be unlikely to realize a material, net financial benefit from any reduction in Forward Capacity Auction clearing prices resulting from entry of the New Capacity Resource in the Forward Capacity Market. If, after consideration of such documentation and information, the Internal Market Monitor determines that a load serving entity as described in this Section III.A.21.2.2 would be unlikely to realize a material, net financial benefit from any reduction in Forward Capacity Auction clearing prices resulting from entry of the New Capacity Resource in the Forward Capacity Market, then the Internal Market Monitor will not subject the requested lowest offer price to the mitigation described in Section III.A.21.2.3. For the avoidance of doubt, a Project Sponsor may not utilize the provisions of this Section III.A.21.2.2 if it receives or expects to receive any revenues from a state, or from a political subdivision of a state that is not also a load serving entity, that relate to the development, operation, control, or output of the New Capacity Resource.

As part of the documentation and information the Project Sponsor submits pursuant to this Section III.A.21.2.2, the Project Sponsor must include in its documentation and information a disclosure of any and all direct or indirect relationships or arrangements with a load serving entity regarding the New

Capacity Resource and any other information necessary for the Internal Market Monitor to make the determination described in this Section III.A.21.2.2.

III.A.21.2.3. Consequence of Failing the Conduct Test and Failing to Rebut Presumed Incentive.
If a requested lowest offer price from a New Capacity Resource fails the conduct test and the Internal Market Monitor does not determine the lack of a material, net financial benefit to a load serving entity, as described in Section III.A.21.2.2, the New Resource Offer Floor Price calculated as part of the conduct test shall be used in the Forward Capacity Auction, as described in Section III.13.2.3.2.

As described in Section III.A.21.1.1, the mitigation described in this Section III.A.21.2.3 will not apply to a New Capacity Resource with an FCA Qualified Capacity that does not exceed the capacity threshold set forth in Section III.A.21.1.1, notwithstanding the results of any buyer-side market power review.

III.A.21.3. New Resource Offer Floor Prices.
For any New Capacity Resource for which the Internal Market Monitor is required to calculate a New Resource Offer Floor Price, the Internal Market Monitor shall use the calculation methodology described in this Section III.A.21.3.

A resource having a New Resource Offer Floor Price determined pursuant to this Section III.A.21.3 that is higher than the Forward Capacity Auction Starting Price shall not be included in the Forward Capacity Auction.

(a) When calculating a New Resource Offer Floor Price for any New Capacity Resource, the Internal Market Monitor shall enter all relevant resource capital and operating costs and non-capacity revenue data, as well as assumptions regarding depreciation, taxes, and discount rate into a capital budgeting model 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 default 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). The model horizon shall be longer or shorter than 20 years for a resource's New Resource Offer Floor Price calculation, if sufficiently documented in the offer information submitted pursuant to Sections III.13.1.1.2.2.3, III.13.1.4.1.1.2.8, or III.13.1.4A.1.1.2.6. Adjustments to the model and calculation methodology will be made for certain types of New Demand

Capacity Resources and New Distributed Energy Capacity Resources as described below in this subsection (a):

(i) For Demand Response Assets or Distributed Energy Resources with demand reduction capability, the Internal Market Monitor will model discounted cash flows over the contract life.

(ii) For Demand Response Assets or Distributed Energy Resources with demand reduction capability that are large commercial or industrial customers that use pre-existing equipment or strategies, the Internal Market Monitor will include new equipment costs and annual operating costs, such as customer incentives and sales representative commissions, as incremental costs.

(iii) For Demand Response Assets or Distributed Energy Resources with demand reduction capability that are residential or small commercial customers that do not use pre-existing equipment or strategies, the Internal Market Monitor will include equipment costs, customer incentives, marketing, sales, and recruitment costs, operations and maintenance costs, and software and network infrastructure costs as incremental costs.

(b) The Internal Market Monitor shall compare the requested lowest offer price to the capacity price estimate calculated pursuant to subsection (a), and the resource's New Resource Offer Floor Price 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 or New Distributed Energy 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 or Distributed Energy 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 or Distributed Energy Resource Aggregation, 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 (as described in Sections III.13.1.1.2.2.3(a), III.13.1.4.1.1.2.8(a), or III.13.1.4A.1.1.2.6(a)) to allow the Internal Market Monitor to make the determinations described in this Section III.A.21.3. If the supporting documentation and information 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 Forward Capacity Auction Starting Price.

(v) If the Internal Market Monitor determines that the requested offer price is 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.

(vi) If the Internal Market Monitor determines that the requested offer price is not consistent with the Internal Market Monitor's capacity price estimate, then the New Resource Offer Floor Price 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).

III.A.21.4. Offer Prices for New Import Capacity Resources.

(a) All New Import Capacity Resources (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 subject to the pivotal supplier test in Section III.A.23.

(b) For any New Import Capacity Resource that is subject to the pivotal supplier test in Section III.A.23 that does not seek to specify a price below which it would not accept a Capacity Supply Obligation that is at or above the Dynamic De-List Bid Threshold, the resource's offer price shall be $0.00/kW-month, subject to the provisions of Section III.13.2.3.2(a)(v).

(c) For any New Import Capacity Resource that is subject to the pivotal supplier test in Section III.A.23 and seeks to specify a price below which it would not accept a Capacity Supply Obligation that is at or above the Dynamic De-List Bid Threshold, the Internal Market Monitor shall calculate an Internal Market Monitor-determined offer price for the resource using the methodology for calculating New Resource Offer Floor Prices set forth in Section III.A.21.3. For any New Import Capacity Resource that is not subject to the pivotal supplier test in Section III.A.23, the Internal Market Monitor shall calculate a New Resource Offer Floor Price using the methodology set forth in Section III.A.21.3, if such a calculation is required for the resource under Section III.A.21.2 above.

(d) For any New Import Capacity Resource that is subject to the pivotal supplier test in Section III.A.23 and is found to be associated with a pivotal supplier, if the supplier elects to revise the requested offer prices pursuant to Section III.13.1.3.5.7, the resource's offer prices shall be reduced to equal the lower of (1) the prices determined by the Internal Market Monitor pursuant to subsection (c); or (2) the offer prices as revised pursuant to Section III.13.1.3.5.7. For any New Import Capacity Resource that is subject to the pivotal supplier test and is found not to be associated with a pivotal supplier, if the supplier elects to revise the requested offer prices pursuant to Section III.13.1.3.5.7, the resource's offer prices shall be reduced to the prices revised pursuant to Section III.13.1.3.5.7.

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.

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

	)	
ISO New England Inc. and	)	**Docket No. ER24-_____-000**
NEPOOL Participants Committee	)	
	)	

TESTIMONY OF DR. MATTHEW WHITE
ON BEHALF OF
ISO NEW ENGLAND INC.

I. WITNESS IDENTIFICATION

Q: Please state your name, position, and business address.

A: My name is Matthew White. I am the Chief Economist and Vice President, Market Development and Settlements, for ISO New England Inc. (the "ISO"). My business address is One Sullivan Road, Holyoke, MA 01040.

Q: Please describe your responsibilities in your role at the ISO.

A: My responsibilities include management, direction, and oversight of the design, development, and settlements of the ISO's suite of competitive wholesale electricity markets. To fulfill these responsibilities I supervise the work performed by numerous teams of professionals employed by the ISO, including economists, engineers, market analysts, data analysts, programmers, settlement specialists, and other subject-matter experts.

Q: Please describe your past professional experience and education.

A: 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.A. in Statistics and a Ph.D. in Economics from the University of California, Berkeley.

II. PURPOSE AND ORGANIZATION OF TESTIMONY

Q: What is the purpose of your testimony in this proceeding?

A: The purpose of my testimony is to explain the rationale for the proposed Day-Ahead Ancillary Services Market. This market will procure several new ancillary services jointly with the ISO's existing Day-Ahead Energy Market. I also explain the rationale for proposed competitively-determined compensation and the call-option settlement design for these Day-Ahead Ancillary Services.[1]

Q: How is your testimony organized?

A: In Section III, I provide background on the existing Day-Ahead Energy Market pertinent to the design and rules of the proposed Day-Ahead Ancillary Services Market. I also summarize how the ISO presently arranges to meet the Operating Reserve and forecast load requirements of a reliable next-day operating plan, using out-of-market practices.

In Section IV.A, I explain the myriad shortcomings of these out-of-market practices and the rationale for proposing a Day-Ahead Ancillary Services Market. Section IV.B summarizes the central properties of the proposed market, its sound economic basis, and how its design is finely tailored to rectify the identified shortcomings.

Section V.A introduces the proposed settlement of Day-Ahead Ancillary Services as call-options on Real-Time energy, and its solid foundation on the economic principle of replacement cost. Section V.B explains the associated settlement mechanics for the Day-Ahead Ancillary Services Market, and Section V.C

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[1] Capitalized terms used in this testimony but not otherwise defined herein shall have the meaning set forth in the ISO New England Transmission, Markets and Services Tariff (the "Tariff"), the Second Restated NEPOOL Agreement, the Participants Agreement, and in the proposed Tariff revisions submitted as part of this filing.

explains the strike price, an important settlement component that balances costs for consumers and performance incentives for Ancillary Service providers. Section V.D discusses several additional settlement considerations important to the design.

Section VI addresses Day-Ahead Ancillary Services' providers' obligations and the voluntary nature of the market's participation.

III. <u>THE CURRENT DAY-AHEAD MARKET</u>

Q: For background, please describe the ISO's current Day-Ahead Energy Market and its role in procuring energy for the Operating Day.

A: Administering the Day-Ahead Energy Market is a central and longstanding service that the ISO provides to New England, enabling Market Participants to buy and sell energy one-day ahead of each Operating Day. Fundamentally, it serves four physically- and financially-interdependent purposes. First, it establishes transparent, competitively-determined prices, and accepts offers to sell and bids to buy energy, in an efficient and cost-effective manner.

Second, the Day-Ahead Energy Market establishes financially binding forward positions for the supply and demand of energy the next day. That reduces financial risk to Market Participants (that is, the volatility over time in total costs to buyers and total revenues to sellers), relative to a marketplace in which all energy transactions occurred only at the time of physical delivery, in the Real-

Time Energy Market. This is because Day-Ahead prices are inherently less volatile than Real-Time prices; in Real-Time, unanticipated events can swing energy prices higher or lower than Day-Ahead.

Third, the binding financial positions awarded in the Day-Ahead Energy Market provide strong incentives for sellers to ensure their resources will be able to physically perform the next day. This is because if a seller does not physically deliver energy consistent with its Day-Ahead obligation (*i.e.*, the megawatt-hours (MWh) of energy it sold Day-Ahead), the market's settlement rules render it financially liable for the resulting replacement cost of energy the system incurs in Real-Time. Stated simply, sellers have "skin in the game" for their physical performance in Real-Time, as a direct result of their Day-Ahead financial obligations.

Fourth, the obligations established for supply resources (sometimes called suppliers' schedules) in the Day-Ahead Energy Market help the ISO to fulfill certain responsibilities as the region's Reliability Coordinator and Balancing Authority. In particular, the Day-Ahead schedules for generation resources are the primary basis for the ISO's next-day operating plan and for ensuring adequate capabilities to meet established reliability operating standards the next day. These standards are discussed further in Section III of the Testimony of Benjamin Ewing accompanying this filing.[2]

Importantly, the current Day-Ahead Energy Market does not fulfill all of the reliability-related requirements of a next-day operating plan. In particular, there is a notable 'gap' between what the Day-Ahead Energy Market procures each day, and various ancillary services requirements of a reliable next-day operating plan. This filing aims to close those gaps, while satisfying the same four fundamental objectives of a well-designed Day-Ahead market.

Q: Please explain further the interdependent financial and physical roles of the existing Day-Ahead Energy Market. How are Day-Ahead energy obligations settled in Real-Time?

A: The ISO's Day-Ahead Energy Market uses a standard multi-settlement system, based on participants' obligations and prices in both the Day-Ahead forward market and a Real-Time market when physical delivery occurs. The idea is simple: a seller is paid a Day-Ahead price that is established when its Day-Ahead offer is accepted and its Day-Ahead obligation awarded. If the energy it delivers in Real-Time is more than its Day-Ahead obligation, it is paid the Real-Time market's price for the additional amount it delivers. And, if the energy it delivers

[2] *See* ISO New England Inc., *Reliability Standards Supporting Day-Ahead Ancillary Services Requirements – Revised Edition* (Jan. 4, 2023), *available at* https://www.iso-ne.com/static-assets/documents/2023/01/a02a_mc_2023_01_10-12_dasi_reliability_standards_memo.pdf (explaining North American Electric Reliability Corporation and Northeast Power Coordinating Council reliability standards pertinent to the ISO's next-day operating plan, and its relationship to the Day-Ahead Energy Market).

in Real-Time is less than its Day-Ahead obligation, it is charged the Real-Time price for the amount it sold forward but did not deliver.

In the ISO-administered energy markets, the Real-Time price – established when electrical energy is produced and delivered to consumers – reflects the system's incremental (or "marginal") cost of serving consumers' demand.[3] Because of this, when a seller does not physically deliver its forward-sold energy in Real-Time, it is charged – that is, it incurs a financial liability – for its undelivered energy based on the system's cost to acquire energy from the marginal resource in Real-Time.

An analogous multi-settlement process applies to Day-Ahead energy buyers: if a buyer ultimately takes delivery of (*i.e.*, uses) more or less energy in Real-Time than it purchased Day-Ahead, it is charged or credited, respectively, for that difference (or "deviation") at the Real-Time market price.

Q: Why are Day-Ahead energy awards settled in this way, and how does this relate to incentives for resources to be able to perform in Real-Time?

A: This settlement system is based on the economic principle of replacement cost. Specifically, if a seller does not deliver consistent with a financially binding obligation, it must either replace (at or before the time of delivery) the goods it

[3] ISO Tariff, Section III.2.5.

cannot deliver with those from another seller, or it must pay the buyer's cost to do so.

The ISO's Real-Time Energy Market serves both of those functions in one fell swoop: it identifies the least-cost supplier that can deliver incremental energy in Real-Time, and then – using the multi-settlement system described in my previous answer – it charges any Day-Ahead seller that delivers less than its Day-Ahead obligation at the system's Real-Time price. And that price, by design, is the system's incremental cost of acquiring replacement energy.

This system reflects sound economic principles for several reasons. It provides sensible short- and long-term incentives for sellers; it is a no-excuses, fault-irrelevant system; and it is simple, conceptually and in practice. Most importantly, it provides the sellers that regularly clear in the Day-Ahead Energy Market with incentives to undertake investments to improve their resources' performance if doing so is less than the expected cost they would incur to purchase replacement energy over time. That is not only efficient, it also tends to reduce the frequency with which replacement energy must be supplied – thereby lowering the overall cost of operating the power system, to consumers' benefit.

Q: Is this replacement-cost logic expressly part of the Market Rules?

A: Yes. A longstanding provision of the energy market sections of ISO Tariff states:

> In the Real-Time Energy Market . . . 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 . . . .[4]

This directly conveys the economic principle that if a Day-Ahead seller does not deliver consistent with its Day-Ahead obligation, the proper consequence is to replace the energy not delivered (*e.g.,* via a bilateral transaction with another seller), or to pay its replacement cost at the Real-Time energy price.

Q: You noted previously that there exist ancillary services requirements for a reliable next-day operating plan. Should procurement of ancillary services also be based on this replacement-cost principle?

A: In my view, yes. The economic principle of replacement cost, while explained previously in the context of the Day-Ahead Energy Market, is by no means limited in application to only that market. As a matter of principle, it is equally applicable to services that the ISO acquires, on behalf of consumers, in advance

[4] ISO Tariff, Section III.1.10.1(c)(i).

of the Operating Day to ensure a reliable delivery system.

The fundamental rationale is the same as explained above. In order to induce ancillary services providers to undertake cost-effective investments and actions in advance of the Operating Day that would improve their resources' ability to deliver energy on short notice (when needed) in Real-Time, such providers should (1) be properly compensated for taking on ancillary services obligations in advance of the Operating Day, and (2) bear the appropriate replacement cost that the system incurs if they do not deliver energy on short notice (when needed) in Real-Time.

Q: Does the current Day-Ahead market in New England procure ancillary services, consistent with that principle?

A: No. The current Day-Ahead market in New England, which is only a Day-Ahead Energy Market, does not procure any ancillary services.

In industry parlance, the ISO's present practices for arranging ancillary services in advance of the Operating Day are known as "out of market" actions. Specifically, to identify resources' ancillary service capabilities as part of its next-day operating plan, the ISO (1) determines the projected Operating Reserve requirements for each hour of the next Operating Day; and (2) applies constraints that specify a minimum level of Operating Reserve within the Day-Ahead Energy Market's initial unit commitment process. The constraints applied in (2) are unpriced, and the resources with capabilities the ISO relies upon to meet the system's next-day Operating Reserve requirements are neither compensated nor informed of it in the Day-Ahead market.

In summary, no suppliers are awarded Day-Ahead obligations to provide ancillary services, and no compensation is provided on a Day-Ahead timeframe to the resources that the ISO relies upon each day for those essential reliability services.

Q: Does the current Day-Ahead market in New England ensure that the next-day operating plan will satisfy the load forecast?

A: No. The ISO does not presently incorporate the system's next-day load forecast into the Day-Ahead Energy Market. As a result, on many days, the Day-Ahead Energy Market clears less energy from physical supply resources than the ISO's load forecast for one or more hours of the next Operating Day. This phenomenon, which is known as the Day-Ahead "energy gap," is described in detail in the accompanying Testimony of Benjamin Ewing, Section III.C.

Presently, following the clearing of the Day-Ahead Energy Market, the ISO assesses the system's projected energy supply and Operating Reserve capabilities and, if necessary, commits additional resources to meet the ISO's load forecast and Operating Reserve requirements for each hour of the next day. In practice, the ISO generally relies upon the physical supply resources that cleared in the Day-Ahead Energy Market with energy schedules below their maximum capacity in order to cover the load forecast. That is, the ISO counts on resources to operate for longer hours, or to run at a higher power output level, than obligated in the Day-Ahead Energy Market, in order to fill the next day's forecast energy gap.

As with Operating Reserves, no Day-Ahead obligations are awarded, or Day-Ahead compensation is provided, to the resources whose capabilities and additional energy supplies the ISO routinely relies upon to close the energy gap in the next-day operating plan.

Q: What types of resources does the ISO typically rely upon, in its next-day operating plan, to satisfy the "energy gap" and Operating Reserve requirements?

A: As context, resources capable of providing Operating Reserves must have either fast-starting or ramping capability to inject additional power (or to reduce load) on the system, and the ability to do so on short notice. In practice there is not a static set of resources that are relied upon for these capabilities, or to cover the forecast energy gap. Rather, it varies from day to day.

As a general matter, however, the types of technologies the ISO commonly relies upon to meet these next-day operating plan requirements include:

i) Energy storage technologies (including pumped storage and pondage-based hydro-electric facilities) in hours they do not clear in the Day-Ahead Energy Market to generate energy, as such technologies can reliably inject additional energy when dispatched during the Operating Day;

ii) Off-line fast-start dispatchable generators (generally, simple-cycle combustion turbines and internal-combustion units), which infrequently receive Day-Ahead Energy Market schedules and are instead instructed to start during the Operating Day as circumstances require;

iii) Higher-cost 'blocks' of combined-cycle generators that receive Day-Ahead energy schedules below their maximum capacity, which (a) the system may count on to meet projected synchronized (or "spinning") Operating Reserve needs the next day; or which (b) the ISO may plan to dispatch higher or operate for longer than their Day-Ahead Energy Market schedules, in order to satisfy the load forecast.

Looking forward, the ongoing evolution in New England's resource mix will likely change the most economic set of resources to meet these system needs. In particular, New England's capacity market cleared over 1 GW of battery-electric storage resources in the most recent Forward Capacity Auction (counting both new and existing such resources). The economics and fast-ramping capabilities of this technology may prove a highly cost-effective means to meet the system's ancillary services requirements, particularly once those services are scheduled and remunerated within a Day-Ahead market that jointly addresses the system's energy and ancillary services requirements.

Q: Why does the set of resources the ISO relies upon for these system needs vary from day-to-day?

A: The specific resources the ISO may rely upon for these purposes, as part of its next-day operating plan, varies day-to-day because it depends on the Day-Ahead Energy Market's outcomes. The details are many, as they involve resources' physical capabilities including for example their maximum capacity relative to the energy supply schedules for the resources cleared and committed in the Day-Ahead Energy Market; those resources' ramp rates; other available but offline resources' lead-times and capabilities; and the magnitude and duration of the next day's forecast energy gap.

Q: What is the importance of these factors for designing a market to procure ancillary services on a Day-Ahead timeframe?

A: There are several. First, because these daily determinations are inherently intertwined with resources' energy schedules, any mechanism for assigning Day-Ahead obligations to cover the next day's forecast energy gap and projected Operating Reserve requirements must be performed accounting for how resources are cleared in the Day-Ahead Energy Market.

Second, it implies that the appropriate set of resources to compensate for providing these essential capabilities in advance of each Operating Day is not a fixed, static set of resources. Rather, the resources compensated will vary from day-to-day, depending on which resources the ISO relies upon for these purposes.

And it will shift over time as the resource mix changes, with the entry of new technologies that may capably meet these system needs.

Third, when identifying which resources (or portions thereof) to count on to cover the forecast energy gap and Operating Reserve requirements of its next-day operating plan, the ISO's present process does not directly consider their costs. This is a consequence of arranging for these system needs using "out of market" practices prior to the Operating Day. Because there is no market for Day-Ahead Ancillary Services, there are no Day-Ahead offers to provide these services – and any attendant costs are neither observed nor considered.

IV. MARKET-BASED PROCUREMENT OF DAY-AHEAD ANCILLARY SERVICES

A. RATIONALE FOR A MARKET-BASED SOLUTION

Q: At a high level, what are the central shortcomings of how ancillary services are presently arranged Day-Ahead, and what does the ISO seek to achieve?

A: Presently, there are no ancillary service obligations associated with the resources the ISO relies upon to meet the forecast energy gap and the Operating Reserve requirements of the next-day operating plan. That is because there are no Day-Ahead market products for these services that participants can sell and for which the ISO can award obligations.

As a consequence, there is inadequate compensation for the costs that resource owners may incur to ensure these resources are able to perform the next day. Moreover, these resources may face no consequences for non-performance, as they have no Day-Ahead obligations. This is despite the fact that the ISO relies upon them to fill the Day-Ahead energy gap and to respond to unanticipated system conditions in Real-Time – conditions when reliable resource performance matters most.

With this filing, the ISO proposes to procure and transparently price the Day-Ahead Ancillary Services capabilities that are necessary to meet existing reliability requirements for the next-day operating plan, and to compensate the specific resources that the ISO relies upon each day for these system needs.

Q: What concerns arise because there are no Day-Ahead obligations and inadequate compensation?

A: The general concern is that without adequate compensation, obligations, and consequences for non-performance, it is not reasonable to expect resource owners to continue to maintain these fast-start/fast-ramping capabilities, or to take actions in advance of the Operating Day that may be necessary to ensure they can perform on short notice when needed.

In particular, without adequate compensation, the owners of such resources (that do not clear in the Day-Ahead Energy Market) may have neither the necessary wherewithal nor the incentive to take costly actions that can improve their resources' performance the next Operating Day. For example, a battery or pumped storage resource must incur costs to store energy in order to be able to deliver energy on short notice during the Operating Day. An infrequently-operated "peaking" generator may need to arrange additional staff on-site to ensure that it can start-up reliably on short notice the next day, if the ISO is relying upon it for Operating Reserve or to cover the forecast energy gap the next day. And a natural-gas turbine owner may need to make additional fuel arrangements within various nomination cycles to be able to run for longer, or at higher power levels, than it cleared in the Day-Ahead Energy Market in order to help meet a higher load forecast.

The Day-Ahead Energy Market provides no compensation for undertaking such costly activities to the resources (or portions of resources) that do not clear in it, but that the ISO nevertheless relies upon for Operating Reserve and to cover the forecast energy gap the next day.

Q: Why doesn't the Real-Time reserve market provide these resources with adequate compensation for costs incurred in advance of the Operating Day?

A: As context, the ISO has operated a co-optimized energy and reserve market in Real-Time for many years. However, our experience has shown that three features severely limit that market's ability to cover the costs that these resources may reasonably incur, in advance of the Operating Day, to ensure they can perform the next day.

For one, the Real-Time reserve market pays only opportunity costs. That is, the co-optimized Real-Time energy and reserves market calculates the opportunity costs that resources providing Real-Time reserve may incur because – and *only* because – they are not supplying energy at the time. Thus, the Real-Time Reserve Clearing Prices reflect simply the opportunity cost of the marginal reserve resources. As a consequence of this design, there are no bids or offers from resources to supply Real-Time reserve. And, because there are no bids or offers, there is no means for these resources to reflect the direct costs they may incur, in advance of the Operating Day, to be able to supply that service in Real-Time.

Second, in New England, Real-Time reserve prices in nearly all hours annually are zero. According to an analysis by the ISO's Internal Market Monitor, the Real-Time prices for Ten-Minute Non-Spinning Reserve and Thirty-Minute Operating Reserve – of *any* magnitude – were positive in a scant 28 and 21 hours, respectively, in 2022.[5] Stated differently, each price was zero in at least 99.7 percent of all 8760 hours that year. These are the primary (by volume) reserve products in the ISO's real-time market. The frequency of a zero price for Ten-Minute Spinning Reserve was somewhat lower, at 87 percent of all hours.

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[5] ISO New England Inc., *2022 Annual Markets Report*, at 188, *available at* https://www.iso-ne.com/static-assets/documents/2023/06/2022-annual-markets-report.pdf.

However, the ISO meets relatively little (approximately one-fifth, on average) of its Total Reserve Requirement in Real-Time with Ten-Minute Spinning Reserve.[6]

The prevalence of zero Real-Time reserve prices is not a new phenomenon in New England. Rather, it has persisted for several years. On an average annual basis, Real-Time Reserve Clearing Prices for Ten Minute Non-Spinning Reserve and Thirty-Minute Operating Reserve have ranged from a low of nearly $0/MWh to a high of less than $1/MWh each year from 2019-2022, generating little revenue to the providers of these services.[7]

The pervasiveness of zero Real-Time reserve pricing is, in part, also a natural consequence of ensuring reserve capabilities are secured Day-Ahead. In the previous section of this testimony, I explained that within the Day-Ahead Energy Market's initial unit commitment process, the ISO applies constraints to ensure the system's scheduled on-line and off-line resources will be sufficient to satisfy the system's projected Operating Reserve requirements for the next day. These (unpriced) constraints, in nearly all hours, yield an excess supply of fast-ramp and fast-start capability in Real-Time (on resources, or portions thereof, with no Day-Ahead Energy Market obligation). Because the ISO uses, for each of its reserve products in Real-Time, vertical reserve demand curves, the Real-Time Reserve

[6] *Id*. at 39.

[7] *Id*. at 185–9.

Clearing Price that prevails in any hour with excess supply will always be zero.

In summary, for all of these reasons, the Real-Time reserve market does not – and, by its very design, cannot – be expected to cover the costs that resources may reasonably incur in advance of the Operating Day, to assure their performance if needed the next day.

Q: Does this under-compensation problem have potential adverse consequences for these resources over the longer-term?

A: Yes. The adverse impacts of chronic (*i.e.*, day-after-day) under-compensation can also undermine longer-term maintenance and resources' performance. For example, the ability of resources to deliver energy on short notice during the Operating Day can generally be expected to improve by undertaking timely maintenance, or periodic overhauls, or incurring capital expenditures to replace aging components, and so on. Such investments have the benefit of improving the likelihood a resource will successfully start each time it is dispatched over the course of a year.

However, if a resource owner undertakes capital expenditures to improve the performance of a resource that typically provides reserves, it receives no additional energy market revenue during the large number (*i.e.*, the substantial majority) of all hours annually when it is not dispatched. And, as explained in the immediately preceding answer, such a resource would receive nearly nothing during the hours it provides Real-Time Operating Reserves, as those prices are zero in nearly all hours.

For these simple reasons, there are well-founded concerns that the resources that typically supply reserves may not have adequate incentives, nor adequate compensation, to undertake costly capital maintenance or other activities that would maintain or improve their resource's performance. Such activities may have significant benefits from the system's standpoint, but the present market design – more specifically, the absence of a Day-Ahead Ancillary Services market – renders such beneficial activities unprofitable for resources that routinely do not clear in the Day-Ahead Energy Market but that the ISO nonetheless relies on for its next-day operating plan.

Q: Why doesn't the existing Forward Reserve Market resolve these inadequate compensation concerns?

A: The Forward Reserve Market has significant limitations in addressing these concerns. As context, the Forward Reserve Market creates forward obligations for a portion of the system's fast-starting resources that do not normally clear for energy in the Day-Ahead or Real-Time energy markets.

For several reasons, the Forward Reserve Market's compensation is not well-aligned with the set of resources the ISO relies upon as part of the next-day operating plan. The resources relied on in formulating the operating plan can change daily, and they include resources scheduled to be online to provide spinning (*i.e.*, synchronized) reserves. The Forward Reserve Market does not procure or compensate any spinning reserves. It also provides no obligations, nor compensation therefor, outside of certain hours (the Forward Reserve Delivery Period hours) each week. Finally, the Forward Reserve Market has no mechanism for compensating resources the ISO relies upon in its next-day operating plan to cover the forecast energy gap.

As explained further in Section VIII of the accompanying Testimony of Benjamin Ewing, the existing Forward Reserve Market has numerous additional incompatibilities with procuring ancillary services on a Day-Ahead basis. For those and related infirmities, the ISO's External Market Monitor, Potomac Economics, has strongly recommended the dissolution of the existing Forward Reserve Market and the creation of a market for Day-Ahead Ancillary Services instead.[8]

Q: Why don't capacity market payments provide sufficient compensation to the reserve resources that the ISO relies on for its next-day operating plans?

A: New England's Forward Capacity Market ("FCM") incents investors to build new resources, or to keep existing capacity in service, and to offer to supply energy

[8] *See* Potomac Economics Inc., *2021 Assessment of the ISO New England Electricity Markets*, at ix, xvi, *available at* https://www.iso-ne.com/markets-operations/market-monitoring-mitigation/external-monitor.

with them in the Day-Ahead and Real-Time Energy Markets. But the FCM does not expressly procure fast-ramping/fast-starting capability in any way. Nor does it pay a greater Capacity Clearing Price to resources that newly invest, or keep in service, these fast-ramping/fast-starting capabilities.

More specifically, other forms of compensation and incentives than capacity revenues are important for fast-ramping/fast-starting resources because the system relies upon them in ways that differ from other resources. These capabilities are what the system relies upon when unexpected events occur in Real-Time that require energy, on short notice, above and beyond what was scheduled from suppliers in the Day-Ahead Energy Market. None of those generally costly fast-ramping/fast-starting capabilities are incrementally remunerated by the capacity market's clearing prices or corresponding Capacity Base Payments.

Put simply, a resource with (say) a 1 MW Capacity Supply Obligation ("CSO") receives the same Capacity Clearing Price (and Capacity Base Payment) whether its ramping rate is 1 MW per hour, or 1 MW per minute, or 1 MW per second. While we have all three in the capacity market today, other things equal, the latter provides far more reliability value than the former two when responding to unexpected events in Real-Time, as a reliable operating plan requires.

In sum, the system's needs for fast-ramping/fast-starting capabilities are not expressly procured or directly remunerated by the clearing prices of the FCM.

And, for the reasons explained earlier in this testimony, those capabilities are inadequately compensated in the Real-Time markets presently – and not compensated in the Day-Ahead Energy Market at all.

Q: Why doesn't pay-for-performance, the capacity market's performance bonus-and-penalty system, resolve these inadequate compensation concerns?

A: Resources' Real-Time performance in the New England power system is settled not only at the Real-Time energy and reserve prices, but also based on a performance incentive under the ISO's pay-for-performance ("PFP") capacity market rules. In principle, for resources with reliable fast-ramping/fast-starting capability, the PFP market rules could provide significant additional revenue for the energy or reserve they supply when a PFP event, known as a Capacity Scarcity Condition, occurs.

In practice, this has not been the case. Capacity Scarcity Conditions in New England remain rare, occurring only three times in more than five years (since PFP initially took effect in June 2018). The last of those events was quite brief, lasting less than an hour. This reflects that such events occur only in narrow, stressed-system conditions, when there is an actual shortage of the system's Total Ten-Minute Reserve or Minimum Total Operating Reserve in Real-Time.

Because Capacity Scarcity Conditions are rare in practice, PFP generates little supplemental revenue for even a high-performing fast-starting/fast-ramping resource. By my calculations, a Fast Start Generator that operated perfectly in all three of those events would have earned approximately $3,462 per CSO MW in Capacity Performance Payments, cumulatively, over all five years. To put this amount in context, if that same generator requires two staff on-site to operate it, at a (hypothetical, but plausible) hourly wage of $42 each,[9] its total Performance Payments would not even cover the plant's direct labor costs for those three days (72 hours) – providing no recovery of maintenance costs, capital expenditures to improve resource performance, or activities in advance of the Operating Day necessary to perform.

The summary conclusion from this and the preceding answers' observations is straightforward: the capacity market construct in New England does not resolve the energy markets' inadequate compensation problem for the fast-starting/fast-ramping capabilities that the ISO relies upon each day to meet the requirements of a reliable operating plan.

Q: Beyond the matter of inadequate compensation, are there other problems that arise because ancillary services are not procured Day-Ahead?

A: Yes. By itself, procuring Day-Ahead Ancillary Services to address the inadequate compensation problem is not enough. Day-Ahead compensation must also be

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[9] *See* U.S. Bureau of Labor Statistics, Occupational Employment and Wage Statistics, Series 51-8013, Power Plant Operators (May 2022), *available at* https://www.bls.gov/oes/current/oes518013.htm.

linked to the obligated resources' Real-Time performance. Such linkages should be defined in a simple and way.

A critical shortcoming of not procuring ancillary services in a Day-Ahead market – and of the ISO's present "out of market" practices in lieu thereof – is that it creates no performance-based consequences for the resources that the ISO relies on to meet the projected next-day Operating Reserve requirements and the forecast energy gap. Because they have no Day-Ahead obligations to honor, they incur no liability (or, in uncommon circumstances through other mechanisms, face limited consequences) for that non-performance.

The importance of linking a resource's Day-Ahead compensation to its Real-Time performance cannot be emphasized enough. Fundamentally, that linkage is what ensures that any such compensation is put to good use, to consumers' benefit. Such a linkage should place on each ancillary service provider an appropriate level of financial liability if it offers and receives an obligation and then fails to perform.

Q: Please explain further what you mean by an "appropriate" level of financial liability if an ancillary service provider fails to perform.

A: As a general matter, it is important that any liability for non-performance be set consistent with sound economic principles. A liability that is too great will deter sellers from offering a service, to the detriment of competitive outcomes and adversely impacting consumers' costs. And a liability that is too lenient will fail to motivate resource owners to take actions in advance of the Operating Day to improve their resources' performance. That would not benefit consumers, and will tend to undermine reliability over time.

Fortunately, there is a well-established economic principle to guide how the consequences for non-performance should be determined. That is the principle of replacement cost, as discussed earlier in Section III of this testimony. The purpose is to lead resource owners to internalize the replacement costs that the system incurs, in Real-Time, if a resource offers and is awarded a Day-Ahead Ancillary Services obligation and then fails to perform.

In summary, appropriate compensation for ancillary service obligations in advance of the Operating Day must be balanced with a transparent, replacement-cost-based consequence for non-performance. One of the central objectives of this filing is to achieve precisely that balance.

Q: Doesn't the Forward Reserve Market in New England create financial liabilities for non-performance for some reserve providers?

A: Yes, in certain circumstances. However, those circumstances are limited and uncommon. The Forward Reserve Market has a complex set of penalty rules, but its main Real-Time "Failure to Activate" penalty is administratively restricted to apply in conditions that occur quite infrequently.[10] These conditions are also far narrower than the full range of situations in which the system incurs replacement costs, in Real-Time, if a reserve resource fails to perform.

Moreover, that penalty mechanism applies to only a subset of the reserve resources the ISO relies upon to cover the forecast energy gap and Operating Reserve requirements in its next-day operating plans. For example, it is not applicable to any resources the ISO relies upon to meet the next-day's synchronized reserve requirement, or to any on-line capability the ISO relies upon to cover the forecast energy gap.

Q: Why is the ISO proposing to meet the system's Day-Ahead Ancillary Service needs using a market structure, as opposed to some other method?

A: There are several reasons. First and foremost, competitive markets are a means to find the most cost-effective providers of a service. A high-cost seller that cannot supply a service at a lower price than its competitors will not be selected. This enables the system's needs for these services to be acquired in the most efficient manner, and rewards the providers who are able to meet the system's needs at the lowest cost.

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[10] ISO Tariff, Section III.9.7.2 (explaining that the Forward Reserve Failure-to-Activate Penalty is applied only in the event of a major source-loss contingency requiring special "contingency dispatch" procedures, or in the event of a binding Ten-Minute Reserve Requirement). In 2022, the former occurred only 38 times, a small share of the approximately 50,000 dispatch cases annually; and the latter in approximately three-tenths of one percent of all five-minute intervals that year.

The second reason is price transparency. Price transparency means that each seller knows not only the rate it is paid, but also the rate all other sellers are paid. That disciplines competitive suppliers' prices. For example, it enables a resource owner that may not have previously considered providing a particular ancillary service to evaluate, *prior* to doing so, whether its costs are lower than existing sellers – and to undercut the competition if so. Price transparency thus expands the pool of resources that provide competitive price discipline beyond the set of active suppliers, to all (current and future) system resources with the capability (or that can add the capability) to provide the service.

The third reason is that the ISO-administered markets are grounded on the firm economic foundation of binding, irrevocable offers. There is no "cost plus" opportunity to re-negotiate a clearing price (*i.e.*, a payment rate), or the terms and conditions for the supply of a service. That further serves to discipline sellers' costs. Moreover, it places certain risks – if, say, a Day-Ahead seller's costs turn out to be higher than it anticipated – solely on that supplier. All of that is appropriate and to the benefit of consumers, as suppliers are in the best position to manage their costs and bear such risks.

Last, well-designed markets provide clear, powerful incentives for resources to perform, and to improve their performance over time. This stems from applying the principle of replacement cost for non-performance. As explained previously in this testimony, that provides Day-Ahead sellers of ancillary services with efficient incentives to take whatever actions they can identify to improve their performance, whether on a short-term basis (*e.g.*, arranging input energy or necessary staffing in advance of the Operating Day) or an annual basis (*e.g.*, maintenance capital expenditures), to avoid liability for non-performance. That will tend to lower the system's overall costs over time, and to improve its reliability, both to consumers' benefit.

Q: Are there important benefits of markets' price signals and transparency, looking beyond existing suppliers' costs and performance?

A: Yes. Fundamentally, markets foster innovation. Within the Commission-jurisdictional realm, competition motivates investors to develop new, lower-cost solutions to electric reliability needs and services. By being closely involved in their projects' development, and with their own capital at risk, investors tend to have great visibility into new technologies' expected performance and costs – more so than planners or market administrators, including the ISO. Open, non-discriminatory markets with transparent price signals provide valuable information to investors when evaluating the services that new technologies can cost-effectively provide.

These are not hypothetical considerations, given the rapid state of technological change within the electricity industry presently. For example, as noted previously, the most recent FCA cleared over 1 GW of battery-electric storage resources; and there are over fifteen times that amount presently in the region's Interconnection Queue.[11] While not all projects in that queue will ultimately be built, creating a transparent Day-Ahead market for ancillary services will help the potential investors in these future resources to gauge the expected incremental revenue they would receive if they enter and supply these services (in addition to all other services they provide in the ISO's markets). That information improves financial decisions and facilitates the entry of new technologies that can meet the system's needs at lower costs, with superior performance, or both.

Q: Why is the ISO proposing now to procure ancillary services in its Day-Ahead Market?

A: As the ISO has explained elsewhere at length, New England's power system and its resource mix are in transition.[12] This is being spurred, in significant part, by New England states' policy goals to reduce the region's carbon emissions. As a practical matter, many of the resource mix and energy use changes underway are creating greater variability in electricity supply and demand during the Operating Day, as both have become increasingly sensitive to weather conditions. Moreover, because of the inherent challenges in accurately forecasting the output

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[11] *See* ISO New England Inc., *NEPOOL Participants Committee Report: August 2023*, at 49, available at https://www.iso-ne.com/static-assets/documents/2023/09/september-2023-coo-report.pdf (showing 17,352 MW of projected new battery storage projects).

[12] *See* ISO New England Inc., *Vision in Action: ISO New England's Strategic Plan*, at 3–6 (Oct. 2022), *available at* https://www.iso-ne.com/about/corporate-governance/strategic-plan.

(and consumption) of weather-dependent resources on the power system, these changes will also require a greater ability of the power system to respond to operational uncertainties during the Operating Day. The Commission has recognized these escalating challenges in a series of technical conferences within its broader proceeding on Modernizing Wholesale Electricity Market Design.[13]

These ongoing developments have led the ISO to take a systematic review of the power system's current and future needs, and the modernization of its markets to meet them.[14] A central finding from its work to date are the problems discussed in this section of my testimony, and that these problems can be productively addressed by creating a competitive market for Day-Ahead Ancillary Services.

In summary, the ISO's concern is that resources that supply reserves do not have adequate incentives, nor adequate compensation, to continue to maintain their fast-start/fast-ramping capabilities, or to take costly actions in advance of the Operating Day that would improve their resources' performance. Such costly activities may have significant benefits from the system's standpoint, but the present market design – more specifically, the absence of a Day-Ahead Ancillary

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[13] *See* Order Directing Reports, *Modernizing Wholesale Electricity Market Designs*, 179 FERC ¶ 61,029 at PP 2–5 (2022).

[14] Report of ISO New England Inc., *Modernizing Wholesale Electricity Market Designs*, Docket No. AD21-10-000, at 55–59 (filed Oct. 18, 2022), *available at* https://www.iso-ne.com/static-assets/documents/2022/10/ad21-10_response_to_order_directing_reports.pdf (summarizing a range of planned energy and ancillary service market reforms related to the ISO's expected changing system needs).

Services market – renders such beneficial activities unprofitable for resources that do not clear in the Day-Ahead Energy Market yet the ISO counts as part of a reliable next-day operating plan. Without the reforms proposed in this filing, I expect the adverse consequences of this "gap" in the ISO's markets will only become worse as the system's needs for resource flexibility and performance grow over time.

Q: Have others also identified a growing need to address flexible resources' compensation and to procure ancillary services in a Day-Ahead market?

A: Yes. In its *2021 Assessment of the ISO New England Electricity Markets,* Potomac Economics, the External Market Monitor, explained a number of factors contributing to a recommendation that the ISO procure ancillary services within its Day-Ahead Market.

Among them, "[u]nder-compensating generators that have flexible characteristics will be increasingly undesirable as the penetration of intermittent renewable generation increases over the coming decade because these resources will be essential to complement the intermittent resources and maintain reliability."[15] It found that "[p]rocuring and pricing these requirements in the day-ahead market

[15] Potomac Economics Inc., *2021 Assessment of the ISO New England Electricity Markets*, at 28–29, *available at* https://www.iso-ne.com/markets-operations/market-monitoring-mitigation/external-monitor.

would result in substantial additional net revenues, especially for flexible resources such as fast-starting peaking units and battery storage units that will be helpful for integrating intermittent renewable generation."[16]

The External Market Monitor concluded: "Therefore, we recommend that the ISO implement operating reserve requirements in the day-ahead market that are co-optimized with energy. This should include … [both] systemwide [sic] forecasted energy and reserve requirements."[17]

Q: Have the problems you have identified resulted in any acute reliability situations to date?

A: To date, no. There have been no loss-of-load events in New England attributable to the performance of reserve-providing resources. Accordingly, the ISO's reliability-related concerns are prospective. Nevertheless, it befits a Reliability Coordinator responsible for ensuring the performance of the New England system not only in the present but looking forward to the future. The shortcomings explained previously in the compensation, obligations, and incentives for reserve-providing resources, in conjunction with the growing dependence on flexible resources to cover any energy gaps and to operate an increasingly weather-sensitive power system, are leading the ISO to proactively address the present

[16] *Id*. at 32.

[17] *Id*.

deficiencies in its Day-Ahead Ancillary Service practices.

B. DESIGN OF THE PROPOSED DAY-AHEAD MARKET

Q: At a high level, what are the central features of the proposed Day-Ahead Ancillary Services Market?

A: The central features follow the standard properties of a well-designed procurement market for a physically-delivered service. They are eight, summarized as follows.

First, the Day-Ahead Ancillary Services Market will procure well-defined products. These products correspond to, and specifically address, the forecast energy and projected Operating Reserve requirements of a reliable next-day operating plan.

Second, the markets for these services are open and non-discriminatory. Any seller with a generation or demand-side resource that meets the product-specific requirements for a particular Ancillary Service is open to participate. For time-denominated (*e.g.*, ten- and thirty-minute response) reserve products, these Day-Ahead requirements are the same as those applicable to Real-Time Operating Reserve providers.

Third, the market will procure obligations associated with physical resources in the New England system. Such resources must have the established capability to deliver energy, in Real-Time, within applicable product-specific timeframes and quantities. For example, the maximum amount of ten-minute reserve procured from a particular resource for a specific hour of the next day is the amount of power that the resource is capable of delivering within ten minutes, above and beyond its Day-Ahead energy obligation (if any).

Fourth, the Day-Ahead Ancillary Service market allows sellers to submit resource-specific, priced offers for each product. This enables sellers to cover not only their expected costs but also to account for their performance risk. Consequently, lower-priced offers are generally expected from resources with greater confidence in their Real-Time performance.

Fifth, the ISO will clear energy and award ancillary services obligations in a jointly optimized Day-Ahead Market that selects the most cost-effective combination of all offers to simultaneously meet buyers' bid-in demand for energy, the system's forecast energy requirement, and the system's Operating Reserve requirements.

Sixth, the Day-Ahead Market will produce transparent clearing prices for energy and each ancillary service product, for each hour of the next Operating Day. Consistent with the principle of marginal-cost pricing in a competitive market, each clearing price is calculated based on the system's marginal cost to procure an incremental amount of each service. These transparent clearing prices comprise an open, non-discriminatory rate paid to all suppliers with a cleared (accepted) offer, and signal the incremental revenue that would be available to any potential new supplier.

Seventh, all Day-Ahead Ancillary Services have a simple, transparent settlement rule that applies the principle of replacement cost. I explain this settlement rule, and how the principle of replacement cost is operationalized, in detail in Section V below in this testimony.

Finally, while we expect the proposed Day-Ahead Ancillary Service Market to be competitive, as a safeguard the proposed new market rules include a well-crafted mitigation design to protect consumers against the possibility of market power. That component of the proposal is described in detail in the Testimony of Dr. Parviz Alivand accompanying this filing.

Q: What specific ancillary services will the ISO now procure in the Day-Ahead Market?

A: There are four specific Day-Ahead products, each serving a specific system need and aligned with existing reliability standards.

One of these new services procures incremental Day-Ahead obligations from resources in the exact amount necessary to cover the forecast energy gap. As noted earlier in Section III of this testimony, the energy gap occurs when the Day-

Ahead Market clears less energy supply from physical resources (including net imports) than the ISO's forecast Real-Time energy demand. The energy gap typically varies from one hour to the next, and from day-to-day; it is zero in any hour when all Day-Ahead energy supply (including net imports) cleared on physical resources exceeds the ISO's forecast Real-Time demand.

To help resolve this gap, we propose to procure an innovative new ancillary service, called Day-Ahead Energy Imbalance Reserve ("EIR"). 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 Day-Ahead cleared energy obligations of the system's physical supply resources is too low to cover forecast Real-Time energy demand for the applicable hour, the Day-Ahead Market may now procure Energy Imbalance Reserve obligations from additional physical resources (or from resources' additional capabilities above their Day-Ahead energy schedules) to resolve that gap.

Q: Can you provide a simple numerical example of when Energy Imbalance Reserve would be procured, and when it would not be?

A: As a simple example, suppose the forecast Real-Time energy demand for a specific hour of the next day is 20 gigawatt-hours (GWh). As a first case, suppose that Day-Ahead total cleared energy demand for that hour is 19 GWh, all of which is cleared against energy supply offers from physical (*e.g.*, generation) resources.

In this case the jointly-optimized Day-Ahead Market will close this 1 GWh energy gap by clearing up to 1 GWh of Energy Imbalance Reserve. (I say ‘up to’ because the Day-Ahead Market may also clear additional energy, as explained presently). In the simple case when Energy Imbalance Reserve fills the entire1 GWh energy gap, we now have combined obligations for energy and for Energy Imbalance Reserve from physical resources that exactly cover the forecast:

$$19 \text{ GWh } \textit{of energy supply} + 1 \text{ GWh } \textit{of EIR} \geq 20 \text{ GWh } \textit{forecast demand}.$$

As a second case, assume the forecast Real-Time energy demand is 20 GWh as before, but now suppose that total cleared energy supply from physical resources is 21 GWh. This exceeds the forecast of 20 GWh, so no Energy Imbalance Reserve is needed or procured:

$$21 \text{ GWh } \textit{of energy supply} + 0 \text{ GWh } \textit{of EIR} \geq 20 \text{ GWh } \textit{forecast demand}.$$

Taken together, these two cases illustrates an important observation. The first case indicates that since Energy Imbalance Reserve is procured at a price, the jointly-optimized Day-Ahead Market will procure it *only* to the extent necessary to close the energy gap. The second case shows that if sufficient energy supply clears economically in the Day-Ahead Market from physical resources to cover forecast energy demand for an hour of the next Operating Day, the amount of Energy Imbalance Reserve cleared for that hour will be zero.

Other numerical examples and detailed design considerations, including the system's forecast energy requirement and how External Transactions (imports and exports), Demand Response Resources, and Increment and Decrement (virtual) transactions are treated when procuring Energy Imbalance Reserve, are explained in Section IV of the Testimony of Benjamin Ewing accompanying this filing.

Q: Will resolving the forecast energy gap in this way change how much energy clears in the Day-Ahead Market?

A: Yes. An important, but subtle, property is that if suppliers' offer prices make Energy Imbalance Reserve expensive in any hour (relative to the cost of incremental energy), then the Day-Ahead Market will clear more energy overall to help meet the forecast. Stated differently, because it is jointly-optimized, the Day-Ahead Market may find it cost-effective to clear additional energy (*i.e.*, to clear farther "up" participants' bid-in energy supply curve) in order to reduce the quantity, and the cost, of procuring Energy Imbalance Reserve to close the energy gap. When this occurs, the total energy cleared will not exceed the forecast energy requirement, however.

In essence, the jointly-optimized clearing of energy and Energy Imbalance Reserve has a built-in, dynamic, hourly cost-control mechanism. It can substitute energy for Energy Imbalance Reserve whenever clearing more of the former is more cost-effective than the latter. Numerical examples and further explanation of this efficient market-clearing property of energy and Energy Imbalance Reserve are further described in the accompanying Testimony of Benjamin Ewing, Section VI.B.

In sum, Day-Ahead Energy Imbalance Reserve is an innovative new Ancillary Service that ensures the system is prepared so that, at the ISO's option, it can dispatch additional flexible resources – with obligations, compensation, and consequences for non-performance – to cover the hourly forecast energy demand for the next Operating Day.

Q: What are the other proposed Day-Ahead Ancillary Service products?

A: There are three additional Day-Ahead Ancillary Service products. Collectively, we refer to them as Day-Ahead Flexible Response Services. They procure resource-specific obligations associated with fast-ramping/fast-starting capability, in order to prepare the system with the capabilities necessary to meet existing Operating Reserve requirements during the next Operating Day.

Specifically, the jointly-optimized Day-Ahead Market will procure obligations for Day-Ahead Ten Minute Spinning Reserve, which will be awarded to resources that have energy schedules in the Day-Ahead Market and dispatchable spinning (*i.e.*, synchronized) capability to deliver additional energy within ten minutes' notice. It will also procure Day-Ahead Ten-Minute Non-Spinning Reserves, which, generally, will be awarded to resources that do not have Day-Ahead energy schedules and that have fast-start energy delivery capability within ten-minutes' notice. And it will procure Day-Ahead Thirty-Minute Operating Reserves, which may be awarded to resources with or without Day-Ahead Energy Schedules, in amounts that reflect their capability to deliver energy (whether from an off-line state, or above their Day-Ahead energy schedule) within thirty-minutes' notice.

These Flexible Response Services serve the system's needs to be prepared to respond, within the ten- and thirty-minute timeframes prescribed in existing reliability standards, to unanticipated events and contingencies during the Operating Day.[18]

Q: Is it appropriate to view these products as obtaining through a market the flexible response capabilities that are presently obtained, without compensation, using "out of market" practices in advance of the Operating Day?

A: Yes. As explained in Section III in this testimony, in establishing its next-day operating plan, the ISO presently applies constraints that specify required flexible response capabilities within the Day-Ahead Energy Market's initial unit commitment process. These constraints and requirements are unpriced. The

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[18] *See supra* note 2.

identified resources with these capabilities, which the ISO relies upon to meet these requirements of a reliable next-day operating plan, are neither compensated nor obligated within the Day-Ahead market.

In my view, that is appropriately characterized as an out-of-market process. In contrast, with this filing, the ISO is bringing into the markets the pricing and procurement of these flexible response capabilities. Doing so will then provide appropriate compensation, obligations, and consequences for non-performance to the resources the ISO relies upon for these capabilities in the system's next-day operating plan.

Q: How will Flexible Response Services be allocated to an individual resource, if it has the capability to provide more than one?

A: As context, certain ancillary service products have shorter response time requirements than others. This affects their clearing and pricing, in logical ways. For example, all ten-minute reserve products will have equal or higher clearing prices than thirty minute reserves. This reflects the fact that a MW that can be delivered in ten minutes has more reliability benefit to the system than if that same MW can be delivered only within thirty minutes.

If a resource has the capability to deliver a certain number of MW within ten minutes, and further MW within thirty minutes, the jointly-optimized Day-Ahead Market will account for that capability and allocate Flexible Response Service obligations accordingly. Generally, this means the MW a resource can deliver within ten minutes will be obligated and compensated at the clearing price for either Day-Ahead Ten-Minute Spinning Reserves or Day-Ahead Ten-Minute Non-Spinning Reserves (generally depending on whether the resource is concurrently awarded an energy schedule in the Day-Ahead Market); the additional MW that it can deliver between ten-minutes and thirty-minutes would be compensated at the (same or lower) clearing price for Day-Ahead Thirty Minute Reserves.

There is no locational or zonal differentiation among the Day-Ahead Flexible Response Services, as all of the Day-Ahead Ancillary Service products will be procured on a system-wide basis.

Q: Why is the ISO proposing to procure the four Day-Ahead Ancillary Services products on a system-wide basis, rather than a locational or zonal basis?

A: As context, for more than a dozen years the ISO has maintained four reserve zones in its jointly-optimized Real-Time energy and reserve market. However, because of substantial investment and upgrades to New England's transmission system over this period, the internal interfaces defining these reserve zones no longer constrain the availability of reserves to the rest of the system. For example, in 2022, there were zero hours in which any zonal reserve requirements were binding (which indicates a constrained reserve zone interface). Because of this, expanding the scope of the present filing to procure reserves aligned with

New England's four existing reserve zones would have little or no benefit.

Cognizant of the substantial investments to date in New England's transmission system, and that many new large-scale resources (such as off-shore wind) are expected in new locations later this decade, the ISO is planning to undertake a significant effort to re-evaluate the system's locational reserve needs and potentially to define new reserve zones.[19] This is presently in the ISO's work plans to commence in 2025.[20] Provided the instant filing is accepted by the Commission, the ISO anticipates that any proposed new reserve zones would be implemented in both the Real-Time and the Day-Ahead energy and ancillary services markets.

From an implementation standpoint, it would be an inefficient use of the ISO's software design and development resources to expand the present proposal to address new reserve zones, prior to that broader effort to evaluate their appropriate new locations.

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[19] *See supra* note 14, at 55–57 (explaining the rationale for, and some developments that may impact, future reform of New England's reserve zones).

[20] *See supra* note 12, at 16 (listing a subset of the ISOs current and future projects, and showing the Reserve Zone Reforms project scheduled to commence in 2025).

Q: Please elaborate on what it means to say that energy and the four ancillary services products will be procured in a jointly-optimized Day-Ahead Market.

A: At a high level, the term “jointly optimized” refers to finding the most cost-effective combination of energy and ancillary service obligations to clear on all of the system’s resources. This will be performed while simultaneously accounting for, in an economic manner, Market Participants’ bid-in demand for energy Day-Ahead and the ISO’s forecast energy demand.

Conceptually, for any resource with both a Day-Ahead energy Supply Offer and a Day-Ahead Ancillary Services Offer, clearing a jointly-optimized market involves evaluating whether each MW of the resource’s capability is more cost-effectively used for energy or for one of the four ancillary services (or, perhaps, for none of these). To avoid double-counting a supply resource’s capabilities, each of its MW can be obligated for – and compensated for – the supply of either energy, or Energy Imbalance Reserve, or a Flexible Response Service. What makes this evaluation involved is that when the same evaluation is made for each offered MW of any other resource, the most cost-effective answer depends on the outcome contemplated for the first resource. In other words, the set of Day-Ahead obligations for all resources must be determined concurrently – *i.e.,* jointly optimized.

This inter-dependent clearing logic applies to the cost-effective means of determining which resources to award what obligations in the multi-product Day-

Ahead Market. It is implementable using iterative numerical processes (and sophisticated software) to simultaneously determine the final Day-Ahead Market obligations for each product and each resource, for the many hundreds of resources participating in New England's Day-Ahead Market each day.

Additional explanation and numerical examples of this jointly-optimized market clearing process, and the corresponding determination of products' market clearing prices, is provided in Section VI of the Testimony of Benjamin Ewing accompanying this filing.

Q: How does a jointly-optimized Day-Ahead Market target compensation to the appropriate ancillary service resources?

A: This market design provides compensation to the appropriate ancillary service suppliers each day, in two ways. First, because Day-Ahead compensation is awarded only to resources with Day-Ahead obligations, and Day-Ahead obligations are awarded to the most cost-effective set of resources that meet the system's (bid-in and forecast) energy demand and ancillary service requirements, the compensation therefore accrues to the most cost-effective suppliers each day.

Second, and critically, this also accounts for the physical characteristics necessary to cover the forecast energy gap and Operating Reserve capabilities of a reliable next-day operating plan. The Day-Ahead obligations awarded to resources for ancillary services are assigned based not only on resources' offer costs for such services, but also on each resource's physical capabilities (*e.g.*, its ramping rate, startup time, maximum output relative to its cleared energy schedule for the same hour of the next Operating Day, and so on). In this way, compensation is appropriately provided to a set of resources with the physical capabilities necessary to provide energy in Real-Time within the requisite time-frames for each ancillary service – and that provide the most cost-effective means to do so for the next Operating Day.

This differs from today, because the costs of supplying an ancillary service are not presently accounted for in the "out of market" practices currently used to meet the system's forecast energy and Operating Reserve requirements of the ISO's next-day operating plan.

Q: Does the procurement of Flexible Response Services in the Day-Ahead Market provide a platform for additional flexible services in the future, as the system's needs evolve?

A: Yes. As a practical matter, and as the region's multi-year effort to produce this very filing attests, it is an involved process to design and implement a jointly-optimized market, to develop all the associated settlement rules and systems, to address any necessary market power mitigation protocols, and so forth. Once created, however, this jointly-optimized Day-Ahead market and its suite of new ancillary services provides a valuable platform for more readily implementing new types of Flexible Response Services in the future.

That more-rapid deployment capability for new Flexible Response Services is likely to become important as the New England system continues in its transition toward a decarbonized system, where far more energy is supplied from weather-sensitive renewable energy resources – and where extreme weather may become more prevalent. For example, to address evolving operational uncertainties, new Flexible Response Services could be added with longer allowed response times (which may have lower costs), but greater energy-duration requirements to protect the system from prolonged (*i.e.*, multi-hour) unanticipated energy supply reductions.

The details of any other type of new Flexible Response Service, beyond the ten- and thirty-minute products discussed previously, would be addressed in a future filing and are not part of the instant proposal. However, the potential for the instant filing to enable the ISO to implement a valuable new platform with additional, future Flexible Response Services would further facilitate the modernization of New England's organized electricity markets. Ultimately, that would help enhance reliability by preparing the system for a greater range of uncertainties in advance of each Operating Day.

Q: Can you summarize what aspects of the proposed Day-Ahead Market in this filing are generally similar to practices in other Commission-jurisdictional organized markets, and what aspects are 'new' innovations?

A: The ISO's proposal in this filing builds on a number of proven fundamentals of energy and ancillary service market designs. It also makes two key innovations.

By itself, jointly optimizing the procurement of energy and (one or more) Operating Reserve products is nothing new. The ISO has been doing so in its Real-Time market for over fifteen years. Several other ISOs/RTOs also have jointly-optimized Day-Ahead markets for energy and (one or more) time-denominated ancillary service products. The logic of how sellers' offers are cleared in a cost-effective manner, and the determination of transparent Day-Ahead market-clearing prices based on marginal-cost pricing principles, are also similar as proposed in this filing and in several other organized electricity markets.

Building upon that foundation, there are two aspects of the present proposal that are innovative. The first is the incorporation of the forecast energy requirement (*i.e.*, the load forecast) into the clearing of the Day-Ahead market, and the procurement of a new type of ancillary service, Energy Imbalance Reserve, to close the energy gap whenever it would occur. This brings into the market a longstanding industry practice of relying upon reliability-based unit commitment processes performed before or after (*i.e.*, outside of) the Day-Ahead market, in order to meet the forecast energy requirement of a reliable next-day operating plan.

The second innovative aspect of the present proposal is the settlement rule for the new Day-Ahead Ancillary Services. This will settle Day-Ahead Ancillary Service obligations based, in part, on the system's incremental cost for energy in Real-Time. The logic and mechanics of this settlement rule I explain next.

V. <u>THE CALL-OPTION SETTLEMENT DESIGN</u>

A. DAY-AHEAD ANCILLARY SERVICES AS AN OPTION ON RESOURCES' ENERGY IN REAL-TIME

Q: At a high level, how will the ISO settle Day-Ahead Ancillary Service obligations?

A: A participant's Day-Ahead Ancillary Service obligation will be settled as a call-option on the underlying resource's energy in Real-Time. This is a simple, standard, and transparent settlement rule.

The reason for this settlement rule is twofold. First, the concept aligns with the essential purpose of reserves, which is to enable the ISO to obtain incremental energy, on short notice, if circumstances require it during the Operating Day. Second, this settlement rule closely aligns with both that purpose and with the economic principle of replacement cost for non-performance.

Q: Why does it make sense to think of Day-Ahead Ancillary Services as a call-option on a resource's energy in Real-Time?

A: Broadly, procuring ancillary services in advance of the Operating Day helps to ensure there will be sufficient resources that the ISO can call upon with short notice, if needed, to balance energy supply and demand the next day. Viewed from a reliability perspective, the fundamental value of Day-Ahead reserves stems from the ISO's ability to call, and the reserve resources' ability to promptly deliver, energy in Real-Time.

Q: Does this mean the ISO is changing how it dispatches resources in Real-Time, based upon their Day-Ahead Ancillary Service obligations?

A: No. The call-option format is a settlement rule, not a change to the Real-Time dispatch process.

Stated in different terms, the ISO is not proposing to prioritize (or to de-prioritize) a resource's dispatch in Real-Time based on a Day-Ahead Ancillary Service obligation. The Real-Time market will continue to jointly optimize energy and reserves to determine which resources are most effective to "call" (*i.e.*, to dispatch) based on least-cost economics, as it does today. This is true both in normal operating conditions, and in potentially stressed system operating situations (*e.g.*, during the tight timeframes for re-balancing supply and demand following a sudden loss of a large supply resource).

Q: To clarify, are any new rules needed to govern when a resource with a Day-Ahead Ancillary Service obligation will be "called" in Real-Time?

A: No. No such new rules are needed – and none are proposed in this filing – to govern when a resource with a Day-Ahead Ancillary Service obligation will be called (*i.e.*, dispatched) in Real-Time. The ISO's joint optimization of energy and reserve in Real-Time can dispatch a resource with a Day-Ahead Ancillary Service obligation whenever its energy is needed, based on least-cost economics and its energy Supply Offer price in Real-Time, precisely because those Day-Ahead obligations are awarded to resources (or portions thereof) with the requisite operational flexibility.

Q: Please explain further.

A: A useful perspective is the following. The jointly-optimized Day-Ahead market, as proposed, is "setting up" the system (*i.e.*, scheduling resources) with the capabilities needed for a reliable next-day operating plan. In doing so, it is procuring the most cost-effective combination of energy and ancillary service obligations on these resources.

The Real-Time market will then "rebalance" which resources are actually used to meet the system's various Real-Time needs (*i.e.*, for energy and Operating Reserves) throughout the Operating Day, as uncertainties and actual loads are realized, in the most economical way (recognizing that many resources submit updated energy Supply Offer prices during the Operating Day, due to New

England's dynamic fuel markets, routinely altering the supply stack between Day-Ahead and Real-Time).

Thus, one can think of the jointly-optimized Day-Ahead Market as ensuring the Real-Time market is set up in a way that it can assuredly handle those uncertainties and loads (up to the limits prescribed in the applicable reliability standards). To consumers' ultimate benefit, this is performed in the most cost-effective way, given the pertinent system conditions at the time, on both the Day-Ahead and Real-Time timeframes.

Q: In that context, what does non-performance mean for a resource with a Day-Ahead Ancillary Service obligation?

A: A resource's non-performance can have many causes and consequences. To fix ideas, it is useful to think of non-performance by a resource with a Day-Ahead Ancillary Service obligation in terms of two general forms. One is of little consequence, and the other more impactful.

The first form arises if the resource is out-of-service (for any number of possible reasons) in its obligation hour during the Operating Day, but Real-Time energy prices remain low and there are more Real-Time reserves than needed to meet the system's requirements. This is not a costly form of non-performance to the system, either from a dollar standpoint or from a reliability standpoint. In such situations, there are sufficient resources to satisfy the system's Real-Time reserve requirements without necessitating any action to replace the out-of-service resource.

Moreover, resources (or portions thereof) that provide ancillary services tend to have relatively high marginal energy costs, and so are uneconomic to operate in low energy-price conditions. As such, if it becomes unavailable when low-price conditions prevail, there is no need to replace its (foregone) energy either: it would not have been in demand economically (*i.e.*, in merit) anyway.

Q: What is the more impactful form of non-performance?

A: A second form of non-performance occurs if a resource with a Day-Ahead Ancillary Service obligation is dispatched in Real-Time, and fails to deliver energy. This type of non-performance can be very costly, both with respect to potential reliably consequences and in economic terms. From a reliability standpoint, there are stringent requirements for the system to respond to, for example, major system disturbances within prescribed timeframes. A failure to perform by the reserve resources the ISO relies upon to deliver energy on short notice can jeopardize system performance consistent with those reliability requirements.[21]

The economic costs arise in a much wider range of Real-Time operating

[21] *See, e.g., supra* note 2 (citing NERC BAL-002, Requirement R.1, and interpretation thereof).

conditions than only when system disturbances occur. Any time a reserve resource fails to deliver energy when in demand economically (*i.e.*, in merit), the ISO must then turn, in often tighter (or at least unexpected) operating conditions than Day-Ahead, to higher-cost resources to replace the energy not delivered by the non-performing resource. That raises the system's total costs and increases the Real-Time price of energy, as a direct result of the resource's non-performance.

Q: What do these two forms of non-performance imply for the replacement cost of a Day-Ahead Ancillary Service resource?

A: The implications are two. The first form implies that if Real-Time energy prices are (and remain) sufficiently low, there is no need to levy a financial charge on a resource with a Day-Ahead Ancillary Service obligation if it is unable to operate in Real-Time. As noted above, resources (or portions thereof) that provide reserves tend to have relatively high marginal energy costs, and so are uneconomic to operate in low price conditions. As such, if one becomes unavailable when low-price system conditions prevail, there is no need to replace its (unneeded) energy – and its unavailability would generally have no impact on Real-Time reserve prices.

However, if Real-Time energy prices are sufficiently high, the situation can be quite different. In such cases, the system may incur substantial incremental costs to replace the energy if a resource with a Day-Ahead Ancillary Service obligation fails to perform. And the appropriate replacement cost, in these situations, should reflect the Real-Time incremental cost of that replacement energy.

Q: To clarify, is that why the replacement cost of a Day-Ahead Ancillary Service resource that does not perform in Real-Time is dependent on the Real-Time cost of energy?

A: Yes, exactly. All of this implies that resources' Day-Ahead Ancillary Services obligations should be settled, at least in part, based on the Real-Time price for *energy*. That is the only way in which such resources' financial liability can be sensibly aligned with the replacement cost of the energy the resource did not provide, both in principle and in practice.

Q: Conceptually, how does a call-option settlement rule capture those two qualitatively different replacement cost possibilities?

A: A call-option settlement rule is a mechanism for charges and credits that captures both of these replacement-cost possibilities. To do so, it produces "bifurcated" Real-Time settlement outcomes. One settlement outcome is designed to apply when the Real-Time energy price is sufficiently low that the resource's energy would not be in demand (*i.e.,* it would not be in merit to operate economically); in such cases, even if the resource is unable to operate, no replacement cost for Real-Time energy would be incurred by the system. Moreover, no replacement cost for Real-Time reserve is likely to be incurred, as Real-Time reserve prices are rarely non-zero – especially in low energy-price conditions.

The other settlement outcome is designed to apply if a resource would be in demand (*i.e.*, it would be in merit if available and able to perform). In such cases, if it does not provide energy in Real-Time, the system would need to use other resources in its place, and incur replacement energy costs based on the Real-Time price of energy.

Q: Please summarize why it is appropriate to settle Day-Ahead Ancillary Service obligations based, in part, upon the Real-Time price of energy.

A: The reason is that by doing so, the markets' settlements can appropriately reflect the replacement cost that the system may incur when a resource with a Day-Ahead Ancillary Service obligation fails to perform.

As explained previously in Section III of my testimony, settling Day-Ahead obligations based on the principle of replacement cost is a hallmark of well-designed markets. For the proposed Day-Ahead Ancillary Services, the call-option settlement rule is designed to create a financial liability for such resources' Real-Time non-performance when that non-performance imposes incremental costs on the system; and it is designed to avoid creating a liability when the system incurs no replacement costs.

A central purpose this settlement logic serves is to lead Day-Ahead Ancillary Service sellers to improve their ability to perform, because they will bear (or "internalize") the incremental replacement cost of Real-Time energy if they do not. That is, in order to minimize their "no excuses" potential settlement liability for non-performance, the owners of the resources that the ISO counts on to meet the system's ancillary service needs will now have strong incentives to take actions – in advance of the operating day – to ensure they are able to perform, if needed, the next day.

More broadly, replacement-cost based market settlements ultimately serve to ensure that consumers benefit from the services they pay for. In the short-term, the Real-Time charges that Day-Ahead Ancillary Service sellers may incur if they fail to perform will accrue, in the proposed daily market settlements, to Real-Time energy buyers (thus, ultimately, to energy consumers), who will forego those charges at the expense of the Day-Ahead Ancillary Service seller. And over the long-term, improvements in reserve resources' ability to perform will tend to reduce the frequency with which higher-cost replacement energy must be generated – lowering the overall cost of operating the power system, to consumers' benefit.

B. MECHANICS OF THE CALL-OPTION SETTLEMENT DESIGN

Q: Please provide an overview of how obligations acquired in the jointly-optimized Day-Ahead Market will be settled.

A: As context, in the 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 jointly-optimized Day-Ahead Market, the ancillary services procured Day-Ahead will also have a second Real-Time settlement, based on those same two elements. However, the second-settlement particulars for energy and for an ancillary service are different. This is because the former will continue to be settled as forward sale (or purchase) of energy, and the latter will be settled as a call-option on energy.

Q: What are the key components of the call-option settlement?

A: A call-option settlement rule involves three components. The first is the Day-Ahead sale of the ancillary service, at its Day-Ahead clearing price. That payment is credited to the seller when the Day-Ahead market clears.

The second call-option component is called the strike price. The strike price is a pre-defined value, set before sellers specify their offers into the Day-Ahead Market. For the moment, think of the strike price as simply a threshold price level, known and applicable to all ancillary service sellers prior to the Day-Ahead Market. This threshold price level will serve to delineate the bifurcated settlement outcomes and to accommodate the replacement cost concepts discussed in preceding Section V.A of this testimony. (I explain how the strike price is set in greater detail in Section V.C, further below.)

The third component is simply the Real-Time price of energy, which is used so that a Day-Ahead Ancillary Service obligation's second settlement depends on the incremental replacement cost of energy.

Q: How are these components combined to apply the call-option settlement rule?

A: In the net settlement of a Day-Ahead Ancillary Service obligation, the seller receives the sum of a charge and a credit. The charge portion, which is commonly called the "close-out charge", is based on the strike price and the Real-Time price of energy. Specifically, for each MWh of the seller's Day-Ahead Ancillary Service obligation, the seller is charged the Real-Time energy price less the strike price, if that difference is positive. This settlement charge can be expressed precisely as a formula:

$$-\max\{0, \text{RT LMP} - K\}.$$

Here, the term RT LMP is an abbreviation for the Real-Time Locational Marginal Price of energy, and the symbol K denotes the strike price value (both of which are in dollars per MWh). The sign at the beginning of this formula is negative because a negative number is a charge (debit) to the participant; a positive number is a credit.

Critically, in addition, the seller also receives credit in the Real-Time settlement for the MWh of energy or reserve its resource actually provides in Real-Time, paid at the Real-Time price of energy or reserve (as appropriate). This Real-Time credit does not depend on the Day-Ahead Ancillary Service award directly.

Q: Mechanically, can you interpret the close-out charge formula?

A: Though it may appear complex, its interpretation is simple. It says that the charge portion of the Real-Time settlement will be zero whenever the RT LMP is lower than the threshold specified by the strike price. That outcome is the first term inside the squiggly brackets in the formula, and corresponds to the first of the bifurcated call-option settlement outcomes.

If the RT LMP exceeds the strike price, however, then the charge portion of the Real-Time settlement will be non-zero. That outcome is the second term inside the formula, and corresponds to the second of the bifurcated call-option settlement outcomes.

Q: Can you please provide a simple numerical example?

A: Yes. Suppose a particular resource has a marginal cost of producing energy of $70 per MWh. It offers and sells 1 MWh of a Day-Ahead reserve product at a Day-Ahead Reserve Clearing Price ("DA RCP") of $5 per MWh, for an hour when the strike price is K = $50 per MWh. In the examples that follow, it does not matter whether the specific Day-Ahead reserve product is Energy Imbalance Reserve or a Flexible Response Service, as the settlement mechanics apply similarly to all.

In a first case, I will illustrate the first of the bifurcated call-option settlement outcomes. Assume the Real-Time LMP is \$25 per MWh, Real-Time reserve prices are zero, and the resource produces 0 MWh of energy in Real-Time (as it is not in merit). Following the settlement steps in my preceding responses, the resource's net settlement is calculated as:

$$\text{DA RCP} - \max\{0, \text{RT LMP} - K\} + 0 \text{ MWh} \times \text{RT LMP}$$

which is:

$$\$5 - \max\{0, \$25 - \$50\} + 0 \text{ MWh} \times \$25 = \$5.$$

Here and generally, the first term is its Day-Ahead Market settlement credit, paid at the DA RCP. The second term is its Day-Ahead Ancillary Services close-out charge in Real-Time, given by the formula explained in the previous answer. The final term is its Real-Time credit for services provided in Real-Time (here zero, as it produces no energy).

In this case, the resource receives the Day-Ahead clearing price of \$5 for accepting the Day-Ahead Ancillary Service obligation, and no money changes hands in later settlements.

Q: How does this call-option settlement reflect the replacement-cost rationale, in such cases when Real-Time prices are low?

A: The case in the preceding question illustrates the first of the bifurcated settlement outcomes generally. When the Real-Time energy price is below the strike price, the resource with a Day-Ahead Ancillary Service obligation is paid the clearing price for the relevant reserve product in the Day-Ahead Market, and is not charged anything in Real-Time.

The underlying idea is straightforward. When the RT LMP is low, it is immaterial whether or not the resource is *able* to perform: because it is not in merit (*i.e.*, its operation would be uneconomic) in Real-Time, then even if it was unable to perform, that would have no cost to the system. Since the system incurs no replacement cost, nothing is charged in Real-Time settlements.

Q: Can you provide an example when the Real-Time energy price is high, and the other settlement outcome applies?

A: Yes. Consider the same setup as in the previous example. However, in this second case, assume the RT LMP is high, at $200 per MWh, and the resource provides 1 MWh of energy in Real-Time as it is now in merit given its $70 marginal cost. (In this and several succeeding examples, the Real-Time reserve price is not needed and omitted.)

Its net settlement is now calculated as:

$$\text{DA RCP} - \max\{0, \text{RT LMP} - \text{K}\} + 1 \text{ MWh} \times \text{RT LMP}$$

which evaluates as:

$$\$5 - \max\{0, \$200 - \$50\} + 1 \text{ MWh} \times \$200 = \$55.$$

In this case, the resource's net settlement simplifies to the DA RCP of $5 plus the strike price of $50, for $55 in total. The resource earns a net Real-Time settlement – that is, the sum of the close-out charge and Real-Time credit – equal to the strike price of $50, rather than the RT LMP of $200, since the Real-Time price is higher than the strike price.

Q: Does the outcome in that example have a standard economic interpretation?

A: Yes, it does. In general, in exchange for the Day-Ahead Ancillary Service clearing price, a seller of a call-option is 'giving up' some of its potential gain from alternatively selling energy only in the Real-Time market. This is its opportunity cost of the Day-Ahead Ancillary Service obligation. In this example it receives a Day-Ahead payment of $5 and a net Real-Time payment at the strike price of $50, forgoing the opportunity of a payment at the Real-Time LMP of $200, for an opportunity cost of $200 – $55 = $145.

Q: Is this analogous to how the Day-Ahead Energy Market works?

A: Although the numbers differ, this opportunity cost interpretation is conceptually analogous to the Day-Ahead Energy Market. For example, if a resource sells 1 MWh of energy Day-Ahead, and the Real-Time market conditions assumed above apply when it delivers its 1 MWh of energy, it would be paid nothing further in Real-Time settlements. Thus, its opportunity cost of selling Day-Ahead energy in this same situation (*i.e.*, relative to selling energy in the Real-Time market) is $200 minus the Day-Ahead LMP, because by acquiring a Day-Ahead energy obligation it is forgoing the opportunity of a payment at the Real-Time LMP of $200.

That opportunity cost of selling Day-Ahead energy differs from selling Day-Ahead Ancillary Services, as the latter depends on the strike price: a lower strike price will increase its opportunity costs, and thereby tend to increase both seller's offer prices and (therefore) the clearing prices for Day-Ahead Ancillary Services. And in theory, if the strike price was set at zero, then the opportunity costs of selling energy and selling ancillary services in the Day-Ahead Market would be virtually the same, as would be their Day-Ahead clearing prices.

In sum, while selling an ancillary service has a different opportunity cost than selling energy Day-Ahead, the economic principles and concepts underlying the existing Day-Ahead Energy Market and the proposed Day-Ahead Ancillary Services Market are quite similar.

Q: What is the settlement if the resource does not deliver energy when the Real-Time energy price is high?

A: In this case, the resource will incur a net charge in the Real-Time settlements commensurate with the incremental replacement cost of the energy it fails to deliver.

This is clear by extending the preceding example, where the Real-Time energy price is $200 per MWh. In this situation the resource would be in-merit if it were able to produce, but now we will instead assume that (for any number of possible reasons) it fails to perform and delivers zero MWh in Real-Time.

In this case, its net settlement is calculated as:

$$\text{DA RCP} - \max\{0, \text{RT LMP} - K\} + 0\ \text{MWh} \times \text{RT LMP}$$

which is:

$$\$5 - \max\{0, \$200 - \$50\} + \$0 = -\$145.$$

Its total settlement is negative: by acquiring a Day-Ahead obligation and then failing to perform when in demand, the resource incurs a net settlement liability (a charge) of $145.

Q: In this situation, how does the call-option settlement rule reflect replacement cost when the resource fails to perform?

A: This situation illustrates a key economic principle, with significant implications for Day-Ahead Ancillary Service providers' incentives. In this case, the seller is compensating the buyer for the incremental replacement cost of energy in Real-Time.

It is important to note that the incremental replacement cost due to the ancillary service seller's non-performance is equal to RT LMP – K, and is not equal to the full RT LMP. The economic logic here is that, when the ancillary service obligation is awarded in the Day-Ahead Market, the system acquired the right to a MWh of its energy for the combination of (i) an up-front price of $5, the DA RCP, and (ii) an incremental price of (at most) K in Real-Time. In Real-Time, the buyer (*e.g.*, load) would have had to pay K = $50 for energy from the Day-Ahead Ancillary Service resource even if it had performed; when it fails to perform, the buyer's incremental replacement cost is just the additional cost it incurs *because of* that non-performance, which is only RT LMP – K = $150.

Stated differently, if the Day-Ahead Ancillary Service seller does not deliver energy in Real-Time when the Real-Time LMP is high, 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. That is the correct replacement-cost logic for the non-performing Day-Ahead Ancillary Service seller, even though some other resource ultimately provides the incremental energy and is paid the full RT LMP.

Q: Please explain further. How do the settlements play out, including the replacement resource that is paid the full RT LMP?

A: Continuing the example, here's how that plays out. The marginal resource that is dispatched (only) in Real-Time and actually delivers the incremental energy is paid, per normal Real-Time settlements, the RT LMP of $200 to supply the 1 MWh of energy not delivered by the seller with the Day-Ahead Ancillary Service obligation. As shown in the preceding response, the Day-Ahead Ancillary Service seller is charged in Real-Time settlements the amount RT LMP – K = $150 for the incremental cost (*i.e.,* in excess of K) to replace its energy. The incremental price paid for the 1 MWh of energy "covered" by the call-option therefore nets to the strike price:

$200 RT LMP *paid for energy delivered*

– $150 charge *to the ancillary service seller*

= $50 strike price.

In that way, regardless of which resource is ultimately dispatched to successfully deliver the incremental 1 MWh of energy in Real-Time, the ISO acquires that 1 MWh of Real-Time energy at a price 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. The proper incremental replacement cost borne by the non-performing Day-Ahead Ancillary Service seller is, in this example and generally, RT LMP – K whenever the difference is positive.

Q: What does this replacement-cost based settlement design imply for Day-Ahead Ancillary Service providers' incentives?

A: This replacement cost logic lies at the economic core of why a call-option settlement design – both in the present context and more generally – helps align incentives efficiently when there is uncertainty over whether the underlying product (here, Real-Time energy) will ultimately be needed.

In the ISO's current Day-Ahead Energy Market, if a resource does not clear and does not produce in Real-Time, its net settlement is zero. By contrast, under the new Day-Ahead Market design, if a resource receives a Day-Ahead Ancillary Service award and does not perform in Real-Time, it incurs a potentially steep financial liability if the Real-Time incremental cost to replace its energy is high. To avoid incurring that "no excuses" financial liability, the resources that the ISO relies upon for the system's essential ancillary services in its next-day operating plan will now have significant incentives to ensure they can perform, if and when dispatched, during the Operating Day.[22]

Q: Does this case capture your earlier point that a sound settlement design should have fault-irrelevant settlement rules?

A: Yes. As I explained at the outset of Section III earlier in this testimony, a key beneficial property of the existing Day-Ahead Energy Market is that it is a no-excuses, fault-irrelevant system. With the call-option settlement rule, the new Day-Ahead Ancillary Service Market maintains these same beneficial properties. No rules are needed to identify and adjudicate why a resource with a Day-Ahead Ancillary Service obligation failed to perform. No settlement conditions must be created to handle exculpatory "it's not my fault" excuses that a non-performing resource owner may seek to put forth (and thereby to shift the cost consequences of its non-performance onto others). As noted previously, such complexities run counter to the clear settlement rules that are the hallmark of well-designed markets, such as the proposed new Day-Ahead Market.

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[22] *See also* ISO New England Inc., *Day-Ahead Ancillary Services Initiative (DASI)*, at 22–25, 31–34 (Nov. 10-12, 2022), *available at* https://www.iso-ne.com/static-assets/documents/2022/11/a08_mc_2022_11_08-10_dasi_presentation.pptx (providing numerical examples that show how the call-option settlement design incents Day-Ahead Ancillary Service providers to undertake costly actions and performance-improving activities in advance of the Operating Day, commensurate with the actions' benefits to the system).

Q: Does this mean a seller faces a risk of loss in its Real-Time settlement if it does not operate?

A: Yes. Suppliers will need to account for that possibility in formulating their offer prices, which may reasonably include a risk premium when acquiring a Day-Ahead obligation. The accompanying Testimony of Dr. Parviz Alivand discusses risk premiums in the context of Day-Ahead Ancillary Services offers in further detail.

Having Day-Ahead Ancillary Service sellers bear risk serves important purposes in this market, where performance is paramount. First, the risk of a net loss in Real-Time settlements will tend to be greatest for resources that generally perform poorly, as the preceding example shows. Risk of a net loss will be much smaller for resources that generally perform well, as an earlier example illustrates (*viz.*, where the resource received a net gain of $55 in total settlements when it performed). That crucial economic difference means the Day-Ahead Market will tend to clear ancillary services on the better-performing resources, as the owners of worse-performing resources will require larger risk premiums – and therefore will tend to submit higher offer prices for Day-Ahead Ancillary Services. In other words, this market provides, by design, a Darwinian competitive advantage to the system's better performing resources. In this way, the market clearing process will identify to the ISO – and enable the ISO to rely upon – the system's better performing resources for its ancillary services needs each day, to the benefit of a more reliable next-day operating plan.

Second, and equally important (if not more), risk serves a valuable economic purpose in that it motivates participants to ensure their resources will be able to perform. Specifically, the risk of loss if a resource fails to perform when needed (*i.e.*, in merit in Real-Time) strengthens each seller's incentives to take proactive actions, in advance of the Operating Day, to ensure their resources can deliver energy, on short notice, if needed in Real-Time. These actions – such as arranging fuel, staffing, or charging a storage resource in advance of an assigned next-day obligation hour – are costly, and those costs become worthwhile to incur precisely because they avoid the liability for non-performance in a "no excuses" settlement design.

Q: Over time, will providing Day-Ahead Ancillary Services tend to reduce, or to increase, overall risk – in the sense of revenue volatility – for the system's fast-starting/fast-ramping resources?

A: Over time, selling Day-Ahead Ancillary Services under the call-option settlement design will tend to reduce the revenue volatility for resources the ISO counts on for these capabilities, relative to if they sell energy in the Real-Time market only (as occurs today). The reason is that Real-Time reserve prices are typically zero, Real-Time LMPs are volatile, and many such resources are only infrequently dispatched – making their revenue stream from the current energy markets highly variable. In contrast, regularly selling Day-Ahead Ancillary Services provides a steady (*i.e.*, daily) payment and much less volatile revenue stream, which is paid whether or not the resource is dispatched for energy that day (or that month).

A second, and more nuanced, reason is that selling a call-option on Real-Time energy is a natural revenue hedge for fast-start resources. In essence, whenever Real-Time prices are high (relative to the strike price), the close-out charge systematically offsets the resource's Real-Time credit for energy, producing a more stable net Real-Time settlement revenue stream over time.

That natural hedge property reduces the variance – which is to say, the overall risk – in a seller's annual net revenues.[23]

Of course, the degree to which a seller's revenue risk is smoothed over time by regularly selling Day-Ahead Ancillary Services will depend on its performance. The reduction in revenue volatility will be greater, other things equal, for better performing-resources. That too will serve to attract the system's better performing resources to participate in the Day-Ahead Ancillary Services market, again to the benefit of system reliability over time.

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[23] *Id*. at 57–67 (explaining, with numerical examples, precisely how selling Day-Ahead Ancillary Services settled as a call-option on Real-Time energy is a natural hedge for fast-start resources (or the fast-ramping capability of online resources), and thereby tends to reduce risk for the resources the system relies upon for these capabilities).

Q: With regard to its Real-Time settlement risk, is it possible that a resource with a Day-Ahead Ancillary Services obligation may incur a close-out charge even if it is available but uneconomic to run in Real-Time?

A: That is possible, though as explained in Section V.C below, the strike price is determined in a manner that seeks to avoid such outcomes. Still, there is a sound economic logic to the applicable Real-Time settlement if this situation arises.

To illustrate, let us continue our prior example but now assume the Real-Time LMP is only \$60 per MWh, and the Real-Time reserve prices are zero. In this situation, the same Day-Ahead Ancillary Service resource's marginal cost of \$70 exceeds the Real-Time LMP of \$60, which in turn exceeds the strike price of \$50. Since the resource is uneconomic to run in Real-Time, it is not dispatched and produces no energy. Its net settlement is now:

$$\text{DA RCP} - \max\{0, \text{RT LMP} - K\} + 0 \text{ MWh} \times \text{RT LMP}$$

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 paid the DA RCP clearing price of \$5 and must then 'buy out' of its Day-Ahead Ancillary Service obligation in Real-Time, at a cost of RT LMP – K = –\$10. In effect, a lower-cost replacement resource is delivering energy (at a price of \$60) instead of the Day-Ahead Ancillary Service resource (with a marginal cost of \$70), while enabling the system to acquire that MWh for the incremental price of K (\$50) in Real-Time at which the ancillary service seller agreed to provide it.

Q: What if the resource provides Real-Time reserve, when Real-Time reserve prices are positive? How is that settled?

A: If a resource is designated in Real-Time for reserve, it would be paid the applicable Real-Time reserve price, regardless of whether it acquired a Day-Ahead Ancillary Service obligation. This may occur when the resource's energy is not in demand in Real-Time, as in the preceding example.

For instance, consider again the previous example but now assume there is a positive Real-Time Reserve Clearing Price ("RT RCP") of $15 per MWh. And we'll assume that the resource provides 1 MWh of Real-Time reserve. In this case, its settlement simply adds an additional credit for the Real-Time reserve it provides, for a total net settlement of:

$$\text{DA RCP} - \max\{0, \text{RT LMP} - K\} + 0\text{ MWh} \times \text{RT LMP} + 1\text{ MWh} \times \text{RT RCP}$$

which is:

$$\$5 - \max\{0, \$60 - \$50\} + \$0 + 1\text{ MWh} \times \$15 = \$10.$$

In summary, if the Real-Time jointly-optimized dispatch of energy and reserve assigns a resource to providing Real-Time reserve, it would continue to be paid for providing Real-Time reserve whenever the applicable RT RCP is not zero.

Q: Is a resource better-off providing Real-Time reserve rather than energy if so assigned in the jointly-optimized Real-Time dispatch?

A: Yes. Despite selling a Day-Ahead Ancillary Service (which settles as a call-option on its energy), a resource is better off providing Real-Time reserve than producing energy whenever so assigned by the Real-Time dispatch. That Real-Time dispatch-following property is unaffected by the sale (or not) of Day-Ahead Ancillary Services.

To illustrate that point, note that in the prior example, if the resource had instead chosen to run in Real-Time (*i.e.*, to "self-schedule" its energy in in the Real-Time market), then it would have a total settlement of:

DA RCP – max{0, RT LMP – K} + 1 MWh × RT LMP + 0 MWh × RT RCP

which is:

$$\$5 - \max\{0, \$60 - \$50\} + \$60 + \$0 = \$55.$$

This looks profitable, but it is not. The reason it is not is because the resource now also incurs its $70 marginal cost to produce that 1 MWh of energy, giving the resource an "all-in" net *loss* of $55 – $70 = –$15. In contrast, the previous example shows in the same situation, the resource would earn a net *profit* of $15 by following its dispatch instruction in Real-Time and providing Real-Time reserve.

We highlight this observation because the point is important: Day-Ahead Ancillary Services obligations do not distort the markets' well-designed incentives for resources to properly follow their assigned Real-Time dispatch.

Q: Tying it all together, can you explain how the Day-Ahead and Real-Time settlements work in concert when a resource provides different amounts of energy and reserve in each market?

A: All of the foregoing examples are special cases of the proposed multi-settlement system applicable with multiple Day-Ahead products. This standard multi-settlement system is particularly useful when the Real-Time market may 'rebalance' which product a resource provides between Day-Ahead and Real-Time.

To explain, consider a final numerical example. Assume that a resource with 3 MW of capacity sells 1 MWh of energy, 1 MWh of an ancillary service, and does not clear the third MW in the Day-Ahead Market for a particular hour of the next day. During the corresponding delivery hour (*i.e.,* in Real-Time), the resource provides 2 MWh of energy and 1 MWh of Real-Time reserve.

That is a lot of numbers to track, but the markets' settlement – here and generally – is straightforward. The Day-Ahead and Real-Time settlement components are easily organized in a table, as shown in below. The resource's total market settlement is simply the sum of the five entries in the Table 1.

Table 1

	DA Sale of Energy	DA Sale of Ancillary Service
Day Ahead Awards (credits)	1 MWh × *DA LMP*	1 MWh × *DA RCP*
Real-Time Close out of Day-Ahead Awards (charges)	–1 MWh x *RT LMP*	–1 MWh × max{0, *RT LMP* – *K*}
Real-Time Supply (credits)	2 MWh × *RT LMP* + 1 MWh × *RT RCP*	

The first row shows the resource's credits (revenue) for its Day-Ahead Market energy and ancillary service sales. In the second row, the resource's Day-Ahead obligations are closed-out based on the Real-Time energy price, as illustrated in preceding examples. The last row shows the resource's credits for the energy and reserve it actually provides in Real-Time, which differs here from its Day-Ahead awards.

This illustrates a general property of the jointly-optimized energy and ancillary services markets: regardless of what product a resource sells in the Day-Ahead Market, all of its Day-Ahead obligations will be closed out based on the Real-Time price, and the resource will be credited for whatever it actually provides in Real-Time at the applicable Real-Time price.

Q: Is this multi-settlement system for forward sales and options novel?

A: No. This multi-product settlement method is commonly employed in commodity markets where participants sell forwards and call-options for the same delivery period. It is not a new or novel multi-settlement design by any means.

Moreover, the existing Day-Ahead Energy Market settlement logic, based on Real-Time energy deviations, is simply the special case in which all Day-Ahead Ancillary Service quantities are 0 MWh. In that special case, by setting the Day-Ahead Ancillary Service quantity (and its closed-out quantity) to 0 MWh and inspecting the table's remaining entries, the resource's total energy settlement simplifies to:

$$1 \text{ MWh} \times \text{DA LMP} + [(2 \text{ MWh} - 1 \text{ MWh}) \times \text{RT LMP}]$$

which is the familiar two-settlement deviation logic for the energy markets' settlements. 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 the resource's "deviation" from Day-Ahead, paid at the Real-Time LMP. In other words, the proposed multi-product settlement design in this filing embodies the same settlement of Day-Ahead energy obligations in use today.

Q: What location is used for the Real-Time Locational Marginal Price in the close-out charge calculation?

A: The ISO will perform the close-out charge calculation using 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 long-standing, stable set of (unconstrained) pricing nodes within New England.

The reason that the call-option closeout charges will be calculated using a system-wide Real-Time energy price is that, foundationally, the new Day-Ahead Ancillary Services are system-level products, each with its own system-wide Day-Ahead clearing price, and not locational products with locational prices. As explained previously in Section IV of this testimony, all of the proposed Day-Ahead Ancillary Service products are system-wide products, procured to satisfy specific system-level requirements of a reliable next-day operating plan.

If, in the alternative, the call-option close-out charges used the nodal LMPs where resources are individually located, then their Day-Ahead Ancillary Service offers would not be true substitutes in the Day-Ahead market. That is, in that alternative, sellers in different locations would receive the same, uniform Day-Ahead clearing price for a particular Day-Ahead reserve product, but would face different settlement rates (and charges for non-performance) despite serving the same system-wide reserve requirement and having identical Real-Time performance.

Q: Does that imply the Real-Time LMPs shown in the second and in the third row of Table 1 may not all be the same value?

A: Correct. Since the call-option close-out charges will be based on the Real-Time Hub Price, the RT LMP shown in Table 1 for the close-out charge (in the second row, right column) is the RT LMP at the system's hub pricing location. That value may differ from the nodal RT LMP applicable to a resource's credit for Real-Time energy produced (in the third row of Table 1).

These Real-Time locational energy price differences may arise due to congestion and marginal energy losses in Real-Time between the hub pricing location and the Day-Ahead Ancillary Service resource's location. However, New England has a robust, generally uncongested transmission system, and as a result I do not expect this design element to prove particularly consequential in practice.

C. DETERMINATION OF THE STRIKE PRICE

Q: Broadly, what is the purpose of the strike price?

A: The strike price serves to balance two objectives. For one, its value impacts the incentives for ancillary service sellers to ensure their resources are reliable and able to perform when needed. Second, its value impacts wholesale market costs, which are ultimately borne by consumers. These two objectives are in a degree of tension, so must be balanced in the design.

Q: Why are these two objectives in tension?

A: Generally, setting a higher strike price value will tend to lower consumers' costs. This is because a higher strike price value lowers sellers' opportunity costs of acquiring Day-Ahead Ancillary Service obligations. That, in turn, will tend to decrease sellers' Day-Ahead Ancillary Service offer prices, and lower the total costs of procuring Day-Ahead Ancillary Services.

However, there is a critical countervailing consideration. A higher strike price value will decrease sellers' incentives to take actions in advance of the Operating Day to ensure their resources will be able to perform. This is because, with a higher strike price, a resource's expected close-out charge decreases (*i.e.*, it would face a smaller financial liability whenever it fails to perform).

In the extreme, if a strike price was set higher than the maximum possible Real-Time LMP, then the call-option's close-out charge would always evaluate to zero. In that case, Day-Ahead Ancillary Service providers would face no liability at all if they fail to perform when needed, and procuring ancillary services in advance of the Operating Day would have little reliability benefit.

Q: Given those considerations, is there an economic basis for how the strike price should be set in principle?

A: Yes. To explain, consider a simple, hypothetical scenario in which all the system's Day-Ahead Ancillary Services can be served by a single resource. In this case, it is economically efficient to set the strike price equal to that resource's marginal cost of supplying energy.

The logic is straightforward. In Real-Time, this resource's energy will be in demand if the RT LMP exceeds the strike price, because that equals its marginal cost. And its energy will not be demanded if the RT LMP is less than the strike price (*viz.*, its marginal cost). Thus there is alignment between when the resource's energy is needed in Real-Time and when the resource is exposed to a net charge in Real-Time settlements if it fails to perform.

The result of this ideal alignment is that the resource bears a close-out charge for its incremental replacement cost whenever its non-performance is consequential to the system (*i.e.*, requires dispatch of another resource to replace it); and it would not bear a close-out charge whenever its inability to perform is non-consequential to the system (because it would not be dispatched in any event).

In this single-resource hypothetical scenario, the economic principle of replacement cost is cleanly achieved with a strike price equal to the resource's marginal cost of supplying energy. The resource would be dispatched for energy when the RT LMP exceeds the strike price, and if it failed to deliver energy, another, higher-cost resource would be required to replace it. The resource's net settlement under the call-option settlement rule is efficient because the seller fully bears its incremental replacement cost, and does so whenever the system incurs that cost.

Q: Is it straightforward to apply this economic principle in practice?

A: In practice, there are three complicating issues. The first issue is one of timing. To facilitate competitive offer pricing by sellers, it is important to set the strike price in advance of the Day-Ahead Market. However, prior to observing the Day-Ahead Market's results, it is not possible to know exactly what will be the marginal costs of the resources actually awarded ancillary service obligations that day.

The second issue is that resources' marginal costs vary. In practice the system's ancillary service requirements are large enough to necessitate procuring these services from many resources. They frequently will have different marginal costs of energy, because the ISO relies upon many different types of fast-starting/fast-ramping technologies for these system needs (as previously described near the end of Section III in this testimony). For example, the marginal cost of a fast-starting oil- or gas-fired combustion turbine can be quite different from the marginal cost of a large hydroelectric facility with a vast reservoir behind the dam, and both of those differ from the marginal cost of a battery-electric storage resource that would re-charge each night (or when the sun is shining mid-day).

The third issue is that setting heterogeneous, resource-specific strike prices for Day-Ahead Ancillary Services would be problematic. Even though they have different marginal costs, sound market design requires a single strike price for the market's settlement (for the obligation hour). The reason is that if the strike prices were resource-specific, then the design would produce different payment rates (*i.e.*, total net settlements) for resources with equal Day-Ahead obligations and equal Real-Time performance. That runs contrary to the sound principle of equal compensation for equal service.

Q: On the first of those three issues, why does the strike price need to be set prior to the Day-Ahead Market?

A: If the strike price's numerical value is not fixed before Day-Ahead Ancillary Service offers are due, then sellers would have no way, in advance of submitting their offers, to anticipate how much risk they will be exposed to for a given realization of the next day's Real-Time price.

Put differently, the call-option's Real-Time settlement – 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. If resource owners do not know the value of the strike price prior to when their Day-Ahead offers are due, they would have no obvious way to formulate a competitive offer price for the Day-Ahead Ancillary Services.

For these reasons, the ISO's approach to determining the strike price will fix and publish its value, for each hour of the next Operating Day, prior to the offer submission deadline for the Day-Ahead Market.

Q: How does the ISO's proposed strike price method address the other two complicating issues?

A: We address these issues taking a two-step approach to setting the strike price. The first step is to determine a "base strike price" value that is dynamically calculated, and varies based on the system's expected Real-Time marginal cost. The second step is a "base strike adder", which increases the strike price and reduces consumers' costs, without materially impacting incentives in conditions when performance matters most.

Q: Please summarize how the base strike price is set.

A: The base strike price is set commensurate to the system's expected marginal cost of energy in Real-Time. This is done by setting an hourly base strike price at the (mathematical) expected value of the Real-Time Hub Price for energy each hour. The Real-Time Hub Price is employed because it is an uncongested location (as noted earlier) that reflects the system's marginal cost of energy.

Q: Why set the base strike price commensurate to the system's expected marginal cost of energy?

A: The explanation rests on two observations. First, at the level of an individual resource, there is no additional benefit to setting a strike price below, rather than at, its marginal cost. Second, while resources supplying Day-Ahead Ancillary

Services will have a range of marginal costs, the system's marginal cost will tend to be at the low end of this range. Therefore, the *base* strike price is set to that lower end. Little additional benefit should be gained from a strike price any lower.

The first of these two observations stems from the same insights as in the simple hypothetical scenario with a single resource, explained previously. Since a resource owner would not find it economic to operate at a Real-Time energy price below its marginal cost, setting a strike price below its marginal cost increases its close-out charges without improving its financial benefit from being able to perform.

The second observation arises because resources (or portions thereof) cleared for Day-Ahead Ancillary Services tend to have costs above – and many well above – the system's marginal cost. This is because jointly-optimized markets economically tend to clear lower-cost resources for energy, and assign higher-cost resources (or higher-cost portions of resources) to reserves (provided they have the requisite response and ramping capabilities).

Taken together, these observations augur for setting the base strike price at the system's expected Real-Time marginal energy cost. A value any lower should provide little additional beneficial incentive for resources to be able to perform the next day.

Q: Doesn't the system's marginal cost of energy, and the expected Real-Time Hub Price, vary from day-to-day and over the course of a day?

A: Yes, it does. 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 hourly system load, weather forecasts, next-day gas prices, the season of the year, and other factors.

For those reasons, the ISO proposes to perform a dynamic calculation of the expected Real-Time price that will be used to set a base strike price for each hour of the day. That is, there will be 24 different base strike prices, one for each hour of the applicable Operating Day. These base strike prices will be calculated and posted prior to each day's submission deadline for the Day-Ahead Market.

The ISO has a sophisticated statistical model that it plans to employ for these expected Real-Time Hub Price calculations. This model, while technical, is publicly available and the ISO has reviewed its performance with Market Participants. This statistical model and its performance is explained in detail in the Testimony of Dr. Parviz Alivand accompanying this filing.

Q: What is the reasoning for applying the base strike adder to the base strike price?

A: As noted at the outset of this section, the value of the strike price will impact both resources' incentives and consumers' costs. With a modest adder to the base strike price, it is possible to lower consumers' costs without materially undermining the design's benefits when performance matters most.

The reasoning follows from prior observations. While the economics of joint optimization implies resources with Day-Ahead Ancillary Service obligations will tend to have marginal costs above the base strike price, the heterogeneity of technologies used for these capabilities means that many (and possibly most) will have marginal costs well above it. Setting the strike price higher than the base strike value will not reduce the incentives of those higher marginal-cost resources, up until it reaches the level of their marginal costs. For that reason, a range of strike price values will exist above the expected Real-Time Hub Price that will not necessarily undermine the incentives created by the call-option settlement design. It will, however, tend to reduce consumers' costs.

Thus, we conducted simulation studies to evaluate the impact on the design's performance incentives for ancillary service sellers, and whether a modest increase (the "base strike adder") to the hourly base strike price would maintain the design's strong incentives for resources' performance.

Q: What did you find?

A: The methodology used for these simulation studies, and their detailed results, are set forth in the accompanying Testimony of Dr. Parviz Alivand. Here, I briefly summarize the central findings.

With a modest base strike adder of $10 per MWh to the hourly base strike price, during hours when the system experiences its highest 5% expected energy prices annually, the design retains 95% of the incentives that it provides to Day-Ahead Ancillary Service sellers to ensure their resources are able to perform during the Operating Day (relative to what would be achieved without the base strike price adder). High-price hours are when the system tends to experience its most stressed operating conditions, and when resource performance matters most.

There is also evidence that during hours and days of the year when expected energy prices are low, the percent reduction in the design's performance incentives is greater. However, I do not find this property to be concerning (from an economic or a reliability standpoint), inasmuch as in its low-price hours the system has ample supplies of replacement resources and non-performance has little impact on system costs.

Q: How do you explain these empirical findings?

A: As noted in the Testimony of Dr. Parviz Alivand, these findings are explained by the 'gap' between the hourly base strike price and the marginal energy costs of the specific resources that we expect to clear for Day-Ahead Ancillary Services in different market conditions, based on our detailed simulation studies.

Specifically, during hours with high expected Real-Time energy prices, the resources that clear for Day-Ahead Ancillary Services have marginal energy costs well above the expected Real-Time Hub Price. Few of those resources are therefore affected by the base strike adder's modest increase in the strike price. However, in hours with low expected Real-Time energy prices, a significant share of all the resources that clear for Day-Ahead Ancillary Services have marginal energy costs that are closer to (*i.e.*, within $10 per MWh of) the expected Real-Time Hub Price, and are therefore affected by the adder.

To the broader point, they support quantitatively the conclusion that the proposed base strike adder of $10 per MWh is a reasonable means to reduce the total consumer costs of procuring Day-Ahead Ancillary Services while preserving the call-option settlement design's strong incentives for these resources to be able to perform during conditions when performance matters most.

Q: Would changes in the resource mix over time potentially alter these findings, and the impact of the strike price adder?

A: Over time, this is conceivable. Given the variety of resource technologies that are relied upon today for Operating Reserves and to cover the forecast energy gap (and that clear for Day-Ahead Ancillary Services in our simulation studies), I expect it would take a large shift in this technology base before these findings would change materially. Fortunately, through the Interconnection Queue and other mechanisms, the ISO has multi-year, forward-looking visibility on the resources being developed in our region and their capabilities. As circumstances change in such a way as to suggest that the base strike adder may warrant adjustment, the ISO has the tools and data necessary to update the relevant simulation studies and to evaluate improvements in order to ensure the efficacy of the Day-Ahead Ancillary Services Market design.

D. ADDITIONAL SETTLEMENT CONSIDERATIONS

Q: For the new Day-Ahead Energy Imbalance Reserve procured to help close the forecast energy gap, is there any alternative to the call-option settlement rule?

A: Not to my knowledge. As a general principle of market design, all products procured in advance of delivery require a spot price to settle against, in order to sensibly apply the principle of replacement cost if a seller fails to perform. There is no viable alternative to the call-option settlement design for Day-Ahead Energy Imbalance Reserve obligations because there is no distinct Real-Time reserve product corresponding to it. The Day-Ahead requirement that Energy Imbalance Reserve helps to satisfy is simply the forecast demand for Real-Time energy.

Q: For a participant that offers and acquires a Day-Ahead Flexible Response Service obligation (*viz.*, Day-Ahead Ten Minute Spinning Reserve, Day-Ahead Ten-Minute Non-Spinning Reserves, or Day-Ahead Thirty-Minute Operating Reserve), why shouldn't the Real-Time settlements charge the resource at the Real-Time reserve price?

A: With an energy call-option design, settling these Day-Ahead reserve obligations based on Real-Time reserve prices is neither necessary nor appropriate. Instead, their Real-Time settlement consists of the call-option close out charge and a credit for the energy or reserve it supplies in Real-Time, at the applicable Real-Time price.

There are two reasons that resources with these Day-Ahead reserve obligations are not "settled for deviations" at the Real-Time reserve price. First and foremost, if a resource with a Day-Ahead Ancillary Service obligation fails to perform when in demand economically (*i.e.*, in merit) in Real-Time, the system must dispatch a higher-cost resource in its place. Thus, as explained previously in Sections V.A and V.B, appropriate application of the principle of replacement cost implies its Real-Time settlement must be based on the Real-Time price of energy. If the resource was instead charged only a Real-Time reserve price when it fails to perform, then the settlement design would enable the seller to escape responsibility for buyers' incremental replacement cost.

Alternatively, if a resource with a Day-Ahead Ancillary Service obligation is charged the Real-Time reserve price in *addition* to the energy option close-out charge in Real-Time settlements, the addition would serve no meaningful purpose.

Q: Why would it serve no meaningful purpose? Would there be any practical effect if Day-Ahead Flexible Response Service resources that are unable to perform were charged the Real-Time reserve price?

A: In New England's system, no. The reason is that Real-Time reserve prices are pervasively zero nearly all year. As noted earlier in Section III of this testimony, the significant majority of all Real-Time reserves (by volume) are Ten-Minute Non-Spinning Reserve and Thirty-Minute Operating Reserve, and in 99.7 percent of all hours in 2022 both had a Real-Time Reserve Clearing Price of zero. For Real-Time Ten Minute Spinning Reserve the prevalence of a zero price is less (at 87 percent in 2022), but this product comprises a much smaller share of the system's Real-Time reserve requirements.

As a result, if sellers with Day-Ahead Ancillary Service obligations were additionally charged the Real-Time reserve price for "deviations" in their Real-Time settlements, it would make no meaningful difference – particularly when Real-Time energy prices are low, Real-Time reserves are (consequently) ample and therefore have a zero price.

And, if sellers were *only* charged the Real-Time reserve price when they do not perform, it would be tantamount to no charge for non-performance at all. And that, in turn, would provide weak incentives for these resource owners to take actions in advance of the Operating Day to ensure their resources are be able to perform.

Q: Did those facts and concerns contribute to the ISO's development of the call-option settlement design for its Day-Ahead Ancillary Services?

A: Yes, in part. The persistent zero prices for Real-Time reserves contributed a practical motivation for the development and proposal of the call-option settlement design for Day-Ahead Ancillary Services. More importantly, however, the proposed settlement rules were guided by the need to closely align it with the economic principle of replacement cost whenever a resource that acquires a Day-Ahead obligation fails in Real-Time.

Q: Does the call-option settlement rule differ from the Real-Time settlement rules for Day-Ahead reserves in other ISOs/RTOs?

A: Yes. Generally, other ISOs/RTOs that procure Day-Ahead reserves credit or charge a resource based on the Real-Time reserve price, to the extent the amount of reserve a resource provides in Real-Time deviates from its Day-Ahead award. However, Real-Time charges and settlement designs for ancillary services are not standardized across ISOs/RTOs, and some apply additional charges for non-performance.[24]

Q: Do any other ISOs/RTOs also charge reserve resources based on the Real-Time energy price if they fail to perform?

A: Yes. For example, in the markets administered by the Midcontinent Independent System Operator, reserve resources that fail to deliver energy consistent with a Real-Time energy dispatch instruction are charged for the MWh they fail to deliver at the Real-Time LMP.[25]

While that ISO's Tariff does not elaborate on the rationale for this non-performance provision, I interpret it as consistent with a general concept advanced throughout this testimony: The appropriate financial consequence for non-performance by a reserve resource should reflect the system's incremental replacement cost of energy in Real-Time.

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[24] *See* ISO New England Inc., *Day-Ahead Reserves – Alternative Settlement Design and its Fuel Security Implications,* at 11, *available at* https://www.iso-ne.com/static-assets/documents/2019/12/a6_c_iii_presentation_da_reserves_alternative_settlement_design_fs_implications.pptx (summarizing a survey of reserve market design differences among the nine ISOs/RTOs in the ISO/RTO Council).

[25] Midcontinent Independent System Operator Tariff, Section 40.3.4.e(i), 40.3.4.f(i).

Q: Has the Commission previously approved rules in New England for ancillary services that charge non-performance based on the Real-Time price of energy?

A: Yes. As noted previously in Section III of this testimony, the existing Forward Reserve Market has a Real-Time "Failure to Activate" penalty that applies to resources fulfilling a Forward Reserve Obligation that fail to deliver energy when needed, under certain conditions. The penalty rate is based on (a multiple of) the Real-Time LMP at the time.[26]

This non-performance charge recognizes, at some level, that if a resource with an ancillary service obligation fails to deliver energy when in demand, the appropriate financial consequence should be based on the Real-Time price of energy. However, and as noted previously, the specifics of this particular penalty rule are both complex and limited to a narrow set of Real-Time conditions that occur quite infrequently. That undermines its alignment with the replacement cost logic articulated throughout this Section V.

In contrast, the proposed call-option settlement rule for Day-Ahead Ancillary Services is tightly aligned with the economic principle of replacement-cost settlement for non-performance. That, in turn, will incent efficiency- and reliability-enhancing actions, in advance of the Operating Day, that improve their

[26] ISO Tariff, Section III.9.7.2.

ability to perform when called to deliver energy in Real-Time.

Q: Do the proposed rules include explicit penalties if a Day-Ahead Ancillary Service seller's resource fails to perform when called to deliver energy in Real-Time?

A: No, not as such. The call-option settlement design creates a no-excuses, fault-irrelevant financial liability for a Day-Ahead Ancillary Service seller if its resource fails to deliver energy when in demand. That places financial responsibility squarely on the seller for the incremental replacement cost of energy incurred.

Q: Why not supplement the market settlements with an additional penalty mechanism for non-performance?

A: In the context of the proposed Day-Ahead Ancillary Services, that would be unnecessary and undesirable, for a number of reasons. As noted in Section III, it is important that any liability for non-performance be set consistent with sound economic principles. A liability that is too great will deter sellers from offering a service, to the detriment of competitive outcomes and adversely impacting consumers' costs.

Given the call-option settlement design's replacement cost logic, additional administrative penalties would untether a seller's non-performance liabilities from its economic consequences in Real-Time. That would inefficiently raise their costs of participating in the market. It would lead sellers to raise their offer prices, in order to cover the greater financial risk to which they would be exposed. Or, it may deter eligible and capable performers from participating in the market entirely. Either outcome would increase prices, undermine competition, and ultimately increase consumers' costs – in a way that cannot be economically justified based on the cost-causative consequences of replacing their undelivered energy.

Given the application of the replacement cost logic at the foundation of the call-option construct for the Day-Ahead Ancillary Services, employing an administrative penalty mechanism could also create perverse incentives for sellers to minimize their risk not by improving performance, but by modifying their Real-Time offer parameters in ways that reduce the likelihood they would be asked to deliver. For example, if an additional administrative penalty is applied only when a resource is dispatched, and is based on whether a resource delivers energy consistent with its dispatch, then the potential for a penalty can be minimized by offering the resource's energy in Real-Time at a high price. Deterring that adverse incentive creates a need for tighter, more intensive, and invariably contentious offer-price mitigation reviews and mitigation mechanisms (beyond that necessary to address market power in a competitive market).

Other perverse incentives could arise for a resource to reduce its stated physical capabilities during the Operating Day, inefficiently reducing supply in order to reduce the seller's excessive administrative penalty risk. For example, a resource with a Day-Ahead award could offer a slower ramp rate (which reduces the maximum MW requested by dispatch software), or a lower CLAIM10 or CLAIM30 fast-start capability value (with similar impact), or so on. Countering this behavior necessitates more frequent auditing, investigation, and administrative policing of physical parameter updates that is costly to both participants and to the ISO, and deters market participation generally.

The central point here is a practical one. The replacement cost logic of the call-option construct provides the incentives for performance that the market requires; given this, additional penalties and charges for non-performance are unnecessary and would reduce sellers' incentives to offer their services competitively, and to provide all of their capabilities to the system. Either outcome would raise consumers' costs, and ultimately undermine the system's long-term performance.

VI. <u>PARTICIPATION AND OBLIGATIONS IN THE DAY-AHEAD ANCILLARY SERVICES MARKET</u>

Q: May a Market Participant offer Day-Ahead Ancillary Services without a resource that can deliver energy, like a "virtual supply" offer?

A: No. To offer and acquire a Day-Ahead Ancillary Services obligation, the seller's offer must be associated with a specific physical resource; that resource must be located within the New England Control Area; the associated resource must have an energy Supply Offer, a Demand Reduction Offer, or a Demand Bid (for

Dispatchable Asset-Related Demands), which enables the dispatch process to access the resource's incremental energy or decremental load; the resource must have established ramping and/or fast-start capability, enabling it to respond on the timeframes required by the relevant ancillary service product it clears Day-Ahead; and so on. These conditions are explained extensively in Section IV of the Testimony of Benjamin Ewing. Note that such conditions are appropriately characterized as eligibility requirements to offer Day-Ahead Ancillary Services, as distinct from obligations acquired *as a result* of a seller's offer clearing in the Day-Ahead Ancillary Services Market.

Note further that an offer will be cleared in the Day-Ahead Ancillary Services Market only to the extent that the associated resource has the requisite physical capabilities for each ancillary service product. For example, a resource with audited CLAIM10 and CLAIM30 values that demonstrates it can start-up and deliver (say) 15 MW in ten minutes, and deliver a total of 45 MW in thirty minutes, will be cleared in the Day-Ahead Market for at most 15 MW of Ten-Minute Non-Spinning Reserve and at most an additional 30 MW of Day-Ahead Thirty-Minute Operating Reserve. In this way, the obligations awarded to sellers are closely tied to the demonstrated physical capabilities of the individual resources associated with a Day-Ahead Ancillary Services Offer.

Q: Are there specific performance obligations on participants that sell Day-Ahead Ancillary Services?

A: No. Specific performance obligations that have "teeth" would be tantamount to extra-market penalties, and as explained above such penalties are not necessary or appropriate in the context of this Day-Ahead Ancillary Services Market. Thus, we do not stipulate further new obligations upon clearing an offer in the Day-Ahead Ancillary Services Market, beyond the "no excuses" settlement obligation explained previously. Importantly, and by design, those settlement obligations reflect the system's incremental cost to replace any Real-Time energy that a Day-Ahead Ancillary Service seller does not provide. That is an efficient and economically-correct consequence for a seller's non-performance.

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.

Q: Why not?

A: Layering extraneous obligations over the Day-Ahead Ancillary Services market would be inefficient and costly to consumers. For instance, we do not stipulate additional obligations such as a specific obligation of (only) generators that sell Day-Ahead Ancillary Services to subsequently acquire fuel at any available price (or, in the alternative, to demonstrate the physical unavailability to procure fuel). Logically, if a Day-Ahead Ancillary Service seller is obligated to procure fuel at any price, then the seller may incur costs that well exceed the system's cost to obtain energy from an alternative resource. Such a specific 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.

Q: Please explain further why a specific obligation to acquire fuel, either prior to or upon acquiring a Day-Ahead Ancillary Service obligation, is unwarranted.

A: There are several reasons. Each imply that such an obligation may induce sellers to incur costs that are greater than the benefits those expenditures bring to the system, and would therefore be contrary to efficiency and consumers' benefit.

First, the proposed call-option settlement design already aligns a seller's incentives to incur fuel-related costs with the expected replacement cost of (electric) energy in Real-Time. As explained previously, this alignment is achieved with a mechanism that is simple and economically sound: if the seller fails 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 incremental cost of that replacement energy.

Second, in the context of the Day-Ahead Ancillary Services, it is difficult to specify an appropriate administrative penalty mechanism if a resource fails to fulfill a specific performance obligation – and one that would not also have adverse unintended consequences. As explained at length at the end of Section V.D of this testimony, given the replacement cost logic employed in the Day-Ahead Ancillary Services design, penalties that are mis-aligned with the system's actual replacement costs would increase sellers' prices, undermine competition, and ultimately increase consumers' costs; and they may create perverse incentives for sellers to inefficiently modify their resources' Real-Time offer parameters in ways that reduce the likelihood or amount of energy they would be asked to deliver. Each of these adverse consequences can be costly, and may undermine the system's performance.

Q: Would these concerns persist if, instead of an administrative penalty mechanism, there was an express Tariff requirement for ancillary service sellers to obtain fuel?

A: Yes, these concerns would persist and new ones would arise. The reason is that if a specific performance obligation was promulgated as an explicit Tariff requirement to obtain fuel, such an "extra-market" Tariff requirement 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 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.

Q: But what if a resource fails to perform and the system experiences a reserve or energy shortage, so there may be no replacement resource to turn to?

A: 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 shortages are a 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 prices.[27] In this way, the "replacement cost" that a non-performing Day-Ahead Ancillary Service seller is charged will not

[27] The Real-Time reserve shortage prices are determined by the Real-Time Reserve Constraint Penalty Factor values. *See* ISO Tariff, Section III.2.7A(c).

only reflect the 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.

Because the replacement energy cost charged to a non-performing seller will incorporate the “scarcity” cost of a shortage of reserves whenever it occurs, the seller’s incentive to (*e.g.*) procure fuel is aligned with the cost the system ascribes to the shortage. Real-time 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, signals the benefit of 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 ensure it is able to perform.

In simple terms, this mechanism – and the call-option settlement rule – 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. To impose, on top of the call-option settlement construct, 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 creating and sustaining economically efficient markets.

Q: Do the proposed rules prescribe a "must offer" requirement of Day-Ahead Ancillary Services, for those with a Capacity Supply Obligation?

A: No. Participation in the Day-Ahead Ancillary Services Market is voluntary. A requirement for (suitably capable) resources with Capacity Supply Obligations to submit offers to sell Day-Ahead Ancillary Services is not necessary, and may have adverse consequences.

Fundamentally, the basic design of the Day-Ahead Ancillary Services Market encourages participation, and renders "forced" participation unnecessary. Like any competitive market, it is reasonable to assume that sellers will submit offers that cover their expected costs and a possible premium for risk (inasmuch as, when offering Day-Ahead, a participant's Real-Time settlement is uncertain). The jointly-optimized Day-Ahead Market then uses the accepted offers to determine a uniform clearing price for each Day-Ahead Ancillary Service. Thus, the market's clearing prices will yield infra-marginal rents (that is, an expected profit) for *all* sellers that offer at a lower price than the marginal resources. This competitive market design, common to the ISO's other markets, encourages participation by all resources with the requisite physical capabilities to satisfy the system's Day-Ahead Ancillary Services requirements.

It is important to note that there is also ample physical capability in New England to meet the system's ancillary service needs. As noted in Section III.B of the Testimony of Benjamin Ewing, system information for 2021, for example, show various types of Operating Reserves (from the Day-Ahead operating plan) always exceeded the Day-Ahead Flexible Response Services Demand Quantities each day, and by more than double on average. Moreover, on a Day-Ahead timeframe the system can readily procure still more 10- or 30-minute reserve from online resources than in the historical data, by economically committing additional dispatchable resources with ancillary service offers in a jointly-optimized Day-Ahead Market.

In combination, the incentive to profit by out-competing other potential suppliers, the simplicity of the market design, and the extensive fast-starting/fast-ramping capabilities presently in the system strongly suggest there will be ample participation in the Day-Ahead Ancillary Services Market – without a need for an administrative rule to compel resource owners to participate.

Q: Without a must-offer rule, are you concerned that a significant share of participants would not offer ancillary services on stressed days when there may be high close-out charges?

A: No. If sellers have expectations of high close-out charges, or a heightened risk thereof, they should price that expectation into their offers that day. That may lead to higher offer prices and clearing prices on stressed days, which is an economically logical price signal of stressed operating conditions.

However, it is not economically sensible for reliable performers to simply "not offer" to sell Day-Ahead Ancillary Services under such market conditions. That would be inconsistent with competitive, profit-maximizing behavior because resources would then forego the profit potential if the market clearing price is very high (*i.e.*, higher than their expected close-out charge). Stated simply, in competitive markets, sellers do not "leave money on the table," as would be the case if they did not offer at all.

Q: Is a must-offer rule necessary to address the possibility of strategic (physical) withholding and market power?

A: While the ISO does not propose a must-offer rule for the Day-Ahead Ancillary Services Market, we are mindful of market power concerns. For that reason, with this filing the ISO is proposing a comprehensive market power mitigation design and process, leveraging the familiar existing conduct-and-impact approach in the ISO-administered markets, to safeguard the market and consumers from the potential for market power in Day-Ahead Ancillary Services. That market power mitigation design, along with the formation of competitive offers accounting for expected close-out charges and sellers' risk premiums, is explained in considerable detail in the accompanying Testimony of Dr. Parviz Alivand.

Importantly, under that market power mitigation design, the rules provide for a refined and informative means by which the Internal Market Monitor can identify and address physical withholding, if it arises. This is superior to a blanket must-offer requirement for Day-Ahead Ancillary Services, as it enables the Internal Market Monitor to evaluate the price impact of any potential physical withholding, informing whether observed behavior is consistent with the exercise of market power or explicable on the basis of other legitimate commercial considerations. Moreover, it enables the Internal Market Monitor to consult with participants and consider that information in determining whether strategic (physical) withholding has occurred.

In summary, the proposed market power mitigation design in this filing is a superior method to protect participants from the potential exercise of market power, and renders application of a must-offer rule unnecessary.

Q: Have either of the ISO's market monitors expressed similar perspectives on mitigation for Day-Ahead Ancillary Services?

A: In a public memorandum discussing its views and experience with mitigation of Day-Ahead Ancillary Services, Potomac Economics, the ISO's External Market Monitor, counseled for appropriate mitigation measures in lieu of a must-offer rule for Day-Ahead Ancillary Services. In summary, it stated, "Instead of a must offer requirement, we recommend having ex post market power mitigation measures that are specifically designed to deter physical withholding."[28] Its reasoning noted, "This would allow the IMM [the ISO's Internal Market Monitor] to focus on suppliers that choose not to offer under conditions when it might actually affect prices, and it . . . would also allow the IMM to more fully consider the relevance of explanations provided by suppliers for not offering the products."[29]

Q: The testimony of Dr. Parviz Alivand describes mitigation rules that, in some cases, may subject a large potential seller that does not offer Day-Ahead Ancillary Services to scrutiny for physical withholding. How is that consistent with the idea that participation in the Day-Ahead Ancillary Services Market is voluntary?

A: As a general matter, mitigation rules to deter physical withholding do not compel a resource owner to offer. This is for several reasons.

First, as described in the Testimony of Dr. Parviz Alivand, the screening rules for physical withholding of ancillary services serve to identify non-participation of large potential sellers, with 100 MW or more of Day-Ahead Ancillary Services capability.[30] Many sellers' capabilities are less than this, so their decision to offer

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[28] Potomac Economics, *Day-Ahead Market Power Mitigation*, Memorandum to ISO New England and NEPOOL Markets Committee, at 12 (January 21, 2020), *available at* https://www.iso-ne.com/static-assets/documents/2020/01/a3_b_emm_memo_day_ahead_market_power_mitigation.pdf.

[29] *Id*. at 12.

[30] *See also* Marked Tariff, Section III.A.4.2.1(c).

or not would not exceed these screening thresholds. (As Dr. Alivand explains, the ISO's market power assessment analyses indicate this is a reasonable threshold for when potential physical withholding may warrant Market Monitor review.)

Second, as Dr. Parviz Alivand further explains, all potential withholding identified by these screening thresholds is subject to a price impact test. If a resource's participation (or not) has little or no impact on market prices, then even a large seller's decision not to offer its supply would be inconsistent with a successful exercise of market power. In such competitive-market conditions, it should have no mitigation-related concerns if it elected to not participate in the Day-Ahead Ancillary Services Market.

I recognize, as a practical matter, that in tight market conditions it is conceivable that a seller with substantial ancillary service capability may decide to offer, rather than not to, simply to avoid the possibility of a Market Monitor's scrutiny for potential physical withholding. For that very reason, the Internal Market Monitor will consult with the participant as to the reasons therefor.[31] Thus, a large participant that declines to offer for legitimate commercial reasons, and can support such reasoning with the Internal Market Monitor (either before the Day-Ahead Market or *ex post*), has an avenue for not participating without regulatory consequences.

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[31] *See* ISO Tariff, Section III.A.4.3.

In summary, the market power mitigation rules do not obligate resources to offer into the Day-Ahead Ancillary Services Market. They do place a burden on larger potential sellers, in certain (*e.g.*, tight) market conditions, to be prepared to explain that their decision not to offer is based on legitimate commercial or operational considerations, and is not an exercise of market power to raise market clearing prices. That burden is a practical necessity to ensure that, in the infrequent, limited times when strategic (physical) withholding could become profitable in the Day-Ahead Ancillary Services Market, the markets – and, ultimately consumers – are protected against the potential exercise of market power.

Q: Has the Commission previously approved voluntary provision of ancillary services in New England, without a must-offer rule for resources with a Capacity Supply Obligation?

A: Yes. In fact, none of the other ancillary services that resources can provide in New England are subject to a must-offer rule. These ancillary services include the Regulation Market[32] and the aforementioned Forward Reserve Market.

[32] *See* ISO Tariff, Section III.14.

VII. CONCLUSION

Q: Does this conclude your testimony?

A: Yes.

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

Executed on October 30, 2023 .

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Matthew White, Vice President, Market Development and Settlements and Chief Economist, ISO New England Inc.

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

ISO New England Inc. and	**)**	**Docket No. ER24-_____-000**
NEPOOL Participants Committee	**)**	

TESTIMONY OF BENJAMIN EWING
ON BEHALF OF
ISO NEW ENGLAND INC.

I. WITNESS IDENTIFICATION

Q: Please state your name, position, and business address.

A: My name is Ben Ewing. I am a Principal Analyst in the Market Development department at ISO New England Inc. (the "ISO"). My business address is One Sullivan Road, Holyoke, MA 01040.

Q: Please describe your professional experience and qualifications.

A: I have been with the ISO since May 2009 in various analyst positions. From May 2009 to October 2011, I was an Analyst in the Market Analysis and Settlements department. From October 2011 until January 2016, I was a Senior Analyst in the Market Development department, performing data analysis in support of proposed market design changes. In January 2016, I became a Lead Analyst, and I held this role until late 2019 when I became a Principal Analyst in the Market Development department. In my current role as Principal Analyst, I am responsible for identifying and developing market design improvements for New England's competitive wholesale electricity markets and presenting these market improvements to external stakeholders.

During my time at the ISO, I have provided testimony to the Federal Energy Regulatory Commission (the "Commission") in support of other market rule changes, including revisions to energy market offer caps pursuant to Commission Order No. 831 (Docket No. ER19-2137-000), interim revisions to the energy market offer cap treatment of so-called "fast start" resources (Docket No. ER17-1542-000), changes to natural gas price indices used in determining various strike and threshold prices in ISO markets (Docket No. ER17-337-000), and assorted changes to Net Commitment Period Compensation ("NCPC") credit calculations (Docket No. ER17-2569-00).

Prior to joining the ISO, I received a B.A. in Applied Mathematics from Washington University in St. Louis, and an M.S. in Industrial Engineering and Operations Research from the University of Massachusetts.

II. PURPOSE AND ORGANIZATION OF TESTIMONY

Q: What is the purpose of your testimony in this proceeding?

A: The purpose of my testimony is to support the ISO's Day-Ahead Ancillary Services Initiative ("DASI") by explaining certain design aspects of the proposed Day-Ahead Market, which will incorporate a Day-Ahead Ancillary Services

Market in conjunction with today's existing Day-Ahead Energy Market,[1] and the results of the ISO's impact assessment for the proposed market.

Q: How is your testimony organized?

A: My testimony explains the proposed changes to the ISO's current Day-Ahead Energy Market that will incorporate the Day-Ahead Ancillary Services Market and result in a jointly-optimized Day-Ahead Market for both energy and reserves. Section III discusses how the ISO will procure Day-Ahead reserve products on behalf of the region in order to meet North American Electric Reliability Council ("NERC") and Northeast Power Coordinating Council ("NPCC") standards through a market-based mechanism. Section IV discusses the eligibility requirements a resource must satisfy in order to provide such products. Section V discusses the requirements and mechanics of the Day-Ahead Ancillary Services Offers that resources will submit. Section VI explains the mechanics of how the new joint Day-Ahead Market will clear and price both Day-Ahead energy and ancillary services under the proposed market rules. Section VII explains the settlement of Day-Ahead energy and ancillary services awards under the proposed market rules and cost allocation. Section VIII discusses the proposal to sunset the region's Forward Reserve Market at the same time the ISO implements the new

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[1] Capitalized terms used in this testimony but not otherwise defined herein shall have the meaning set forth in the ISO New England Transmission, Markets and Services Tariff (the "Tariff"), the Second Restated NEPOOL Agreement, the Participants Agreement, and in the proposed Tariff revisions submitted as part of this filing.

Day-Ahead Ancillary Services Market. Finally, Section IX presents the impact assessment representing an estimate of the changes in cost to load and revenues to Market Participants that will result from the implementation of DASI (hereinafter referred to as the "Impact Assessment").

III. <u>PROCUREMENT OF DAY-AHEAD RESERVES AND DEMAND QUANTITIES</u>

A. BACKGROUND: RELIABILITY STANDARDS AND CURRENT PROCESS

Q: What is the intent of the DASI design?

A: As noted in the Testimony of Matthew White, DASI satisfies certain key Day-Ahead reliability requirements through a market mechanism, rather than relying on out-of-market processes. The proposed Day-Ahead Market, which will incorporate a jointly run Day-Ahead Energy Market and a Day-Ahead Ancillary Services Market, will satisfy these key reliability requirements through the procurement of new Day-Ahead Ancillary Services products and adjustments to the way in which Day-Ahead energy is procured.

Q: Can you describe these key Day-Ahead reliability requirements?

A: Yes. Each day, ISO New England must create a Day-Ahead operating plan that addresses two key reliability requirements for the next Operating Day. The ISO must ensure (1) sufficient energy supply capability to satisfy the next-day load forecast and (2) sufficient reserve capability to meet expected Operating Reserve requirements for the Operating Day. These requirements are explicit in NERC and NPCC standards, as well as in the ISO's own operating procedures.

Q: What reliability standards relate to next-day operating reserve requirements?

A: NERC BAL-002-3, Requirement R2, states that, as part of its operating plan, the ISO must "determine its 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." Generally, the term "contingency" refers to a large single source of energy supply, the loss of which could adversely affect system reliability absent sufficient preparation and planning.

NPCC Regional Reliability Reference Directory #5 (Reserve) establishes specific minimum requirements for certain types and amounts of reserves. Specifically, it states that "[e]ach Balancing Authority[2] shall have ten-minute reserve available to it that is at least equal to its first contingency loss" and that "[a] Balancing Authority's minimum requirement for synchronized reserve available within ten minutes shall be 25 percent of its ten-minute reserve." Further, NPCC Directory

[2] A "Balancing Authority" as defined by NERC is the "responsible entity that integrates resource plans ahead of time, maintains load-interchange-generation balance within a Balancing Authority Area, and supports Interconnection frequency in real time." *See* https://www.nerc.com/pa/Stand/MOD%20V0%20 Revision%20RF%20DL/Glossary.pdf. ISO New England a registered Balancing Authority with NERC.

#5 states that "[e]ach Balancing Authority shall have thirty-minute reserve available to it that is at least equal to one-half its second contingency loss." To satisfy these standards, the ISO must calculate reserve requirements based upon the expected first and second contingencies in each hour of the Operating Day, and must ensure sufficient reserve capability is available to satisfy these requirements in each hour of the Operating Day. ISO New England Operating Procedure No. 8 ("OP-8") further establishes the levels of reserves the ISO will procure to satisfy these NERC and NPCC standards.[3]

While these standards identify the reserve requirements for each hour of the Operating Day in Real-Time, NERC-TOP-002-4, Requirement R4, further requires that Balancing Authorities have a Day-Ahead operating plan that addresses "capacity and energy reserve requirements, including deliverability capability." As a result, the ISO considers these reserve requirements when creating its Day-Ahead operating plan.

Q: What reliability standards relate to the next-day load forecast?

NERC-TOP-002-4, Requirement R4, stipulates that Balancing Authorities have a Day-Ahead operating plan that balances "expected generation resource

[3] For further elaboration on the NERC and NPCC standards and OP-8's implementation of these standards, the ISO's memorandum to the NEPOOL Markets Committee provides more detail. *See* ISO-NE Memorandum to NEPOOL Markets Committee, *Reliability Standards Supporting Day-Ahead Ancillary Services Requirements – Revised Edition* (Jan. 4, 2023), *available at* https://www.iso-ne.com/static-assets/documents/2023/01/a02a_mc_2023_01_10-12_dasi_reliability_standards_memo.pdf.

commitment and dispatch . . . interchange scheduling . . . and demand patterns." To satisfy this standard, the ISO calculates an hourly next-day load forecast and develops an operating plan that commits sufficient capacity to satisfy that forecast in each hour of the Operating Day.

Q: How does the ISO currently satisfy these requirements for its Day-Ahead operating plan?

A: Today, the Day-Ahead Energy Market's economic dispatch and pricing process, which occurs by way of the Day-Ahead market clearing engine, does not incorporate the above-mentioned reliability requirements. The ISO instead relies upon out-of-market mechanisms to ensure these requirements are satisfied in its next-day operating plan.

For background, the Day-Ahead market clearing process includes two sequential processes, a unit commitment process and an economic dispatch and pricing process. First, the unit commitment process determines a schedule of resource commitments (*i.e.*, an on/off decision for each resource for each hour of the Operating Day). Next, the economic dispatch and pricing process determines Day-Ahead energy awards for supply and demand, as well as Day-Ahead Locational Marginal Prices ("DA LMPs").

Today, the Day-Ahead Energy Market's unit commitment process incorporates operating reserve requirements, identifying the reserve capability available to satisfy the next day's operating reserve requirements. However, and importantly, these operating reserve requirements are not incorporated in the subsequent Day-Ahead Energy Market economic dispatch and pricing process. As a result, today's Day-Ahead Energy Market produces no awards associated with operating reserves identified for the next day, nor does it produce clearing prices for those reserves. Neither the Day-Ahead Energy Market's unit commitment process nor its economic dispatch and pricing process incorporate the load forecast.

In addition, the ISO performs an out-of-market reliability process known as the Reserve Adequacy Analysis ("RAA") following the clearing of the Day-Ahead Energy Market. The primary focus of the RAA is to review the difference between the ISO forecast load and the total physical resources and net imports that clear in the Day-Ahead Energy Market in order to identify any additional actions (*e.g.*, resource commitments) necessary to ensure a reliable next-day operating plan. The RAA may also commit additional units to meet the next day's operating reserve requirements if insufficient reserve capability was identified through the unit commitment process described above. While it is rare that resource commitments are made as a result of this RAA process, when such commitments are required they are inherently made out-of-market, and have potential to suppress real-time prices and increase NCPC, or uplift, payments.

Q: How does DASI change this process to ensure these requirements are satisfied through market mechanisms?

A: With DASI, these reliability needs will be met by translating these reliability requirements—the expected Operating Reserve requirements and load forecast requirement for the next day—into demand quantities that will be reflected within the new Day-Ahead Market clearing process. The demand quantities will be calculated for each hour of the upcoming Operating Day. The proposed Day-Ahead Market (as noted above, a combination of the Day-Ahead Energy Market and proposed Day-Ahead Ancillary Services Market) will procure four new Day-Ahead Ancillary Services products to help satisfy these new demand quantities through a market mechanism. The four new products are the following: the Day-Ahead Ten-Minute Spinning Reserves ("DA TMSR"), Day-Ahead Ten-Minute Non-Spinning Reserves ("DA TMNSR"), and Day-Ahead Thirty-Minute Operating Reserves ("DA TMOR") (collectively referred to as Day-Ahead Flexible Response Services), which will satisfy the operating reserve demand quantities; and the Day-Ahead Energy Imbalance Reserve ("DA EIR"), which will help to satisfy the load forecast requirements. Market Participants will be able to submit priced supply offers for each of these new Day-Ahead Ancillary Services products, and these supply offers will be considered in determining Day-Ahead Ancillary Services awards and clearing prices and, as explained further below, the Forecast Energy Requirement Price.

B. FLEXIBLE RESPONSE SERVICES DEMAND QUANTITIES

Q: Can you provide a high-level description of the demand quantities related to next-day operating reserves?

A: Yes. These demand quantities are collectively referred to as the Day-Ahead Flexible Response Services Demand Quantities. These demand quantities establish the minimum amounts of Day-Ahead reserve capability that must be procured by the proposed Day-Ahead Market. By Day-Ahead reserve capability, we mean the ability of a resource to increase its energy output to levels above (or, for a demand-side resource, to decrease its energy consumption to levels below) its Day-Ahead cleared energy award within ten and thirty minutes.[4] In total, there are four Day-Ahead Flexible Response Services Demand Quantities: the DA TMSR Demand Quantity, the Day-Ahead Total Ten-Minute Reserve Demand Quantity, the Day-Ahead Minimum Total Reserve Demand Quantity, and the Day-Ahead Total Reserve Demand Quantity. These requirements, as well as the Day-Ahead Flexible Response Services that will satisfy them, are analogous to the ISO's current Real-Time reserve requirements and the Operating Reserve products that satisfy such requirements. With Day-Ahead Flexible Response Services Demand Quantities applied within the Day-Ahead Market clearing engine, the ISO will satisfy the above-mentioned NERC and NPCC standards and produce a next-day operating plan that satisfies expected Real-Time Operating Reserve requirements through a market construct.

[4] This includes fast-start resources that are scheduled as offline (*i.e.*, a Day-Ahead energy awards of zero) but that can increase their output within ten and thirty minutes.

Q: For background, would you please describe the analogous Real-Time Operating Reserve requirements and reserve products that the ISO procures today?

A: The ISO has four reserve requirements that represent reserves the region must have in Real-Time to meet NERC and NPCC standards: the Ten-Minute Spinning Reserve Requirement, the Ten-Minute Reserve Requirement, the Minimum Total Reserve Requirement, and the Total Reserve Requirement. These reserve requirements reflect the NPCC Directory 5 reliability standards discussed above. The Ten-Minute Spinning Reserve Requirement and Ten-Minute Reserve Requirement represent the ISO's two Real-Time ten-minute reserve requirements, and the Minimum Total Reserve Requirement and Total Reserve Requirement represent the ISO's two Real-Time thirty-minute reserve requirements.[5]

To satisfy these reserve requirements, the ISO procures three Real-Time reserve products: Ten-Minute Spinning Reserves ("TMSR"); Ten-Minute Non-Spinning Reserves ("TMNSR"); and Thirty-Minute Operating Reserves ("TMOR"). TMSR is an ancillary service that, generally, can be provided by online resources that can increase their production within ten minutes. TMNSR is an ancillary

[5] The Minimum Total Reserve Requirement is set to satisfy NERC and NPCC Operating Reserve requirements. The Total Reserve Requirement is a thirty-minute reserve requirement that includes both the Minimum Total Reserve Requirement and Replacement Reserves, which is an amount of reserve capability that can respond in 30 minutes or fewer that the region procures for the purpose of meeting NERC's requirement to restore its ten-minute reserves. Replacement Reserves are procured to help satisfy NERC-BAL-002-3, Requirement R.3.

service that, generally, can be provided by resources that are offline, but that can come online within ten minutes. TMOR is an ancillary service that can be provided by resources that can further increase their production within thirty minutes. TMOR can be provided by either online resources, or offline resources that can increase their production within thirty minutes.[6]

Q: Can you describe the reliability need that each of the Day-Ahead Flexible Response Services Demand Quantities addresses?

A: As with the Real-Time Operating Reserve requirements that exist under current market rules, all Day-Ahead Flexible Response Services Demand Quantities reflect the NERC and NPCC reliability standards noted above. However, they are based on Day-Ahead projections of what reserve requirements will be in Real-Time during the Operating Day and will be calculated for each hour of the Operating Day. The DA TMSR Demand Quantity reflects the projected need for ten-minute response capability from resources that will be online and synchronized to the grid. For Day-Ahead scheduling purposes, such capability must be from resources cleared for Day-Ahead energy (*i.e.*, synchronized to the grid in the Day-Ahead context). The Day-Ahead Total Ten-Minute Reserve Demand Quantity reflects the projected need for resources that can inject additional energy within ten minutes or less, from either an online or offline state.

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[6] For a description of the eligibility requirements to provide TMSR, TMNSR, and TMOR, please see Section III.1.7.19.2 of Market Rule 1.

Both the Day-Ahead Minimum Total Reserve Demand Quantity and the Day-Ahead Total Reserve Demand Quantity reflect the projected need for resources that can inject additional energy within thirty minutes or less, from either an online or offline state.[7]

Q: Based on historical data, can you provide a representation of the expected magnitude of these Day-Ahead Flexible Response Services Demand Quantities?

A: Yes. The table below provides summary statistics for each demand quantity used as part of the Day-Ahead unit commitment process for the years 2019 through 2021. All values are expressed in MWh.

Table 1

Demand Quantity	Min	Median	Average	Max
TMSR	444	586	594	771
Total Ten-Minute	1,200	1,584	1,608	2,083
Minimum Total Reserve	1,633	2,208	2,229	2,828
Total Reserve	1,793	2,384	2,396	3,008

[7] The difference between the Day-Ahead Minimum Total Reserve Demand Quantity and the Day-Ahead Total Reserve Demand Quantity is the same as the difference between the analogous Real-Time Minimum Total Reserve Requirement and Total Reserve Requirement—namely, an amount equal to the real-time Replacement Reserves required during the Operating Day. Replacement Reserves are a form of reserve procured for the purpose of meeting the NERC requirement to restore ten-minute reserves within required timeframes following a contingency.

Q: What products can satisfy the Day-Ahead Flexible Response Services Demand Quantities?

A: As mentioned above, DASI introduces a suite of three new Day-Ahead Ancillary Services, collectively referred to as Day-Ahead Flexible Response Services. These products are conceptually analogous to the Real-Time Operating Reserve products that are currently designated in the ISO's Real-Time operations. They are DA TMSR, DA TMNSR, and DA TMOR. As with TMSR in Real-Time, DA TMSR is an ancillary service that, generally, can be provided by resources that can increase their production within ten minutes and are scheduled to provide energy (*i.e.*, online) by the market clearing engine. DA TMNSR is an ancillary service that, generally, can be provided by resources that are offline, but that can come online within ten minutes. DA TMOR is an ancillary service that can be provided by online or offline resources that can further increase their production within thirty minutes. As with Real-Time Operating Reserve products, these Day-Ahead Flexible Response Services products will be "cascaded" to satisfy each of the Day-Ahead Flexible Response Services Demand Quantities.

Q: Please explain what you mean when you say the products will be "cascaded."

A: This "cascading" of products works as follows. The DA TMSR Demand Quantity can only be satisfied by DA TMSR. The DA Total Ten-Minute Reserve Demand Quantity can be satisfied by any combination of DA TMSR and DA TMNSR. The Day-Ahead Minimum Total Reserve Demand Quantity can be satisfied by any combination of DA TMSR, DA TMNSR, and DA TMOR.

Similarly, the Day-Ahead Total Reserve Demand Quantity can be satisfied by any combination of DA TMSR, DA TMNSR, and DA TMOR.

Q: Can you provide a simple numerical example to illustrate this cascading of Day-Ahead Flexible Response Services products across the Day-Ahead Flexible Response Services Demand Quantities?

A: Yes. For example, suppose the Day-Ahead Ten-Minute Reserve Requirement for an hour were 100 MWh and the DA TMSR Requirement were 25 MWh. A resource capable of providing 100 MWh of TMSR in that hour would be able, by itself, to satisfy both of these requirements. The ISO would not need to schedule an additional resource to meet both of its Day-Ahead ten-minute reserve requirements.

Next, suppose the Day-Ahead Minimum Total Reserve Requirement were 300 MWh and the Day-Ahead Total Reserve Requirement were 310 MWh in that same hour. The resource noted above, providing 100 MWh of DA TMSR, would also satisfy part of these two thirty-minute reserve requirements. The ISO would only need to procure an additional 210 MWh to satisfy the Total Reserve Requirement from resources that are capable of providing, at the very least, DA TMOR. In procuring this 210 MWh, the ISO also will have procured the 200 MWh needed to satisfy the Minimum Total Reserve Requirement.

Q: How will this cascading of products be reflected in the proposed Day-Ahead Market?

A: The cascading of products will be reflected in constraints applied within the market clearing engine. Notably, these constraints are formulated identically to those that are applied today for Real-Time Operating Reserves. These constraints are formulated as follows.

- DA TMSR awards ≥ DA TMSR Demand Quantity
- (DA TMSR + DA TMNSR) awards ≥ Day-Ahead Total Ten-Minute Reserve Demand Quantity
- (DA TMSR + DA TMNSR + DA TMOR) awards ≥ Day-Ahead Minimum Total Reserve Demand Quantity
- (DA TMSR + DA TMNSR + DA TMOR) awards ≥ Day-Ahead Total Reserve Demand Quantity

Essentially, DA TMSR awards must be greater than or equal to the DA TMSR Demand Quantity. The combined quantity of DA TMSR and DA TMNSR awards must be equal to or greater than the Day-Ahead Total Ten-Minute Reserve Demand Quantity. This represents the "cascading" of these products described above—namely, that both products are substitutable when it comes to satisfying the Day-Ahead Total Ten-Minute Reserve Demand Quantity. And similarly, the combined DA TMSR, DA TMNSR, and DA TMOR awards must be greater than or equal to both the Day-Ahead Minimum Total Reserve Demand Quantity and the Day-Ahead Total Reserve Demand Quantity.

A penalty factor is considered in each of these constraints, and reflects the maximum cost the region is willing to incur in order to procure certain Day-Ahead products to satisfy that constraint. Penalty factors, and their role in determining the clearing price associated with each Day-Ahead Ancillary Services product, is discussed in Section VI.C below.

Q: How does the system's current aggregate capability to provide Day-Ahead Flexible Response Services compare to the Day-Ahead Flexible Response Services Demand Quantities?

A: On the system today, there is ample physical capability to satisfy these Day-Ahead Flexible Response Services Demand Quantities. For example, during the year 2021, the aggregate system capability able to satisfy the projected, next-day total ten- and thirty-minute reserve requirements was more than 200 percent of the quantities required, on average, and never less than 110 percent of those quantities. It is important to note that, with the proposed Day-Ahead Market, the ISO will be able to procure more ten- and thirty-minute capability, including spinning reserve capability, on a Day-Ahead basis than these historical values reflect, by economically committing additional dispatchable resources with ancillary service offers in the jointly-optimized Day-Ahead Market.

C. FORECAST ENERGY REQUIREMENT DEMAND QUANTITY

Q: Can you describe the demand quantity related to satisfying the next-day load forecast?

A: Yes. This is called the Forecast Energy Requirement ("FER") Demand Quantity, and in each hour it will reflect the ISO's next-day forecast of Real-Time load within the New England Control Area. The FER Demand Quantity will incorporate the load forecast into the Day-Ahead Market to enable an entirely market-based method of satisfying the load forecast.

Q: What products can satisfy the FER Demand Quantity?

A: The FER Demand Quantity can be satisfied by a combination of Day-Ahead energy procured from physical supply resources (Generator Assets, Demand Response Resources ("DRRs"), and net imports) and the new DA EIR product. With the FER Demand Quantity applied, the Day-Ahead Market will procure an economically efficient combination of DA EIR and Day-Ahead physical energy in each hour to ensure that the load forecast can be satisfied for each hour. In turn, this will satisfy the relevant NERC standard through a market-based mechanism.

Q: Please explain how Day-Ahead physical energy satisfies the FER Demand Quantity.

A: The FER Demand Quantity is effectively the Day-Ahead load forecast for an hour of the Operating Day. As explained above, the existing RAA process considers the physical (*i.e.*, non-virtual) supply resources that are cleared in the Day-Ahead

Energy Market in its assessment of the ISO's ability to satisfy the load forecast. With DASI, the load forecast constraint is explicitly considered in the unit commitment and economic dispatch and pricing processes of the Day-Ahead Market. All Day-Ahead energy awards from physical resources, including Generator Assets, DRRs, and net imports (*i.e.*, aggregate Day-Ahead cleared imports less Day-Ahead cleared exports in an hour) will be counted toward satisfying the FER Demand Quantity in each hour.

Q: Please describe the new DA EIR ancillary service product.

A: DA EIR is a Day-Ahead Ancillary Service that can be provided by physical supply resources (*i.e.*, the set of resources that may be dispatched in Real-Time in order to satisfy load). The DA EIR product, like Day-Ahead energy, has a sixty-minute time horizon. This means that an eligible resource may clear a DA EIR award based on its ability to increase output above its Day-Ahead energy schedule within sixty minutes, given its physical characteristics. As explained further below, a resource must either (1) be a fast-start resource or (2) receive a Day-Ahead energy award for it also to receive an award for DA EIR. For example, a resource with a Day-Ahead energy award that has a ramp rate of 1 MW/minute could receive, at most, an EIR award of 60 MWh, given its ability to increase its output over a sixty-minute time period.

Q: How does the new DA EIR product contribute to satisfying the FER Demand Quantity?

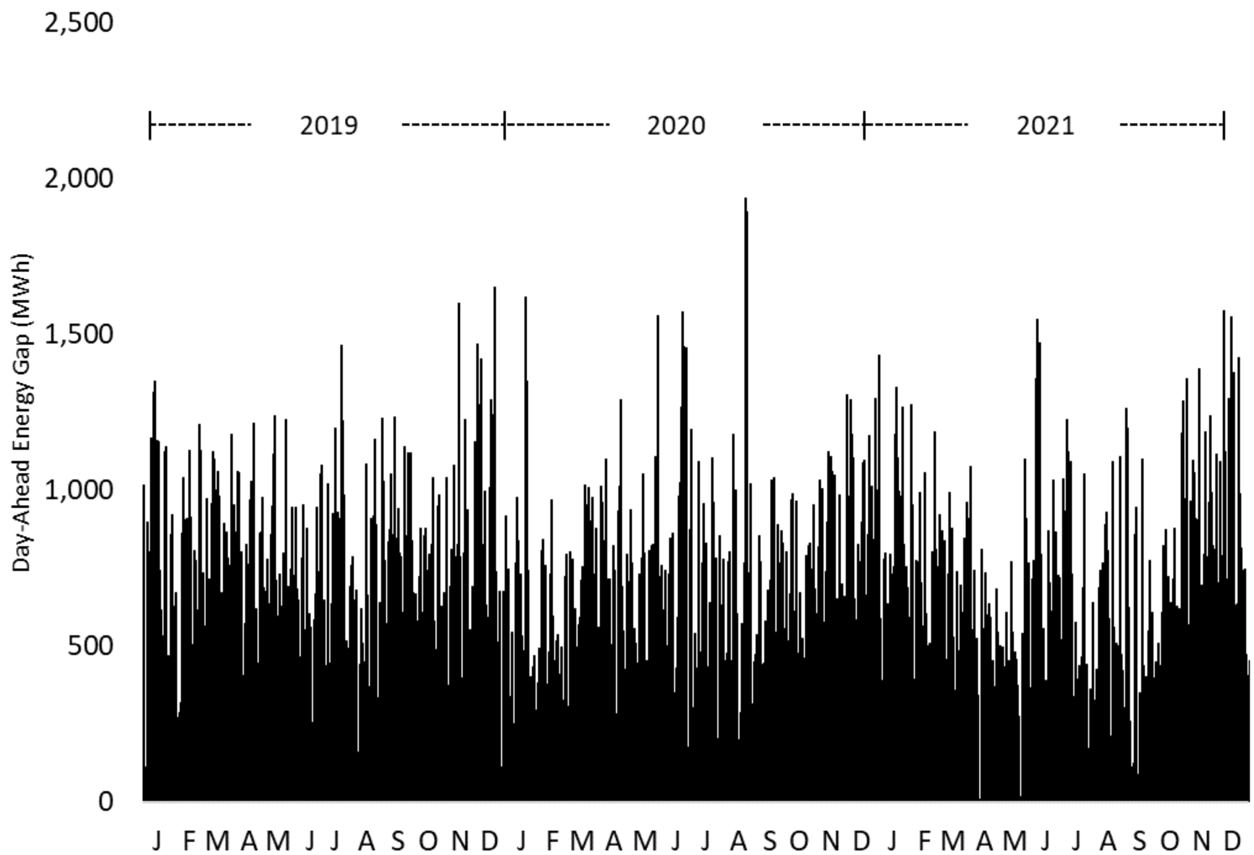
A: All DA EIR awards will be counted, in conjunction with physical Day-Ahead energy awards, toward satisfying the FER Demand Quantity. Notably, DA EIR is a product that will only be procured in hours when a "Day-Ahead energy gap" exists. An hour is considered to have a Day-Ahead energy gap if, under current market rules, the total energy cleared in the Day-Ahead Energy Market on Generator Assets, DRRs, and net imports is less than the load forecast in that hour. Increment Offers (*i.e.*, "virtual supply") that clear in the Day-Ahead Energy Market are not considered when determining the Day-Ahead energy gap. DA EIR is a reserve product that can be procured to help close some or all of a Day-Ahead energy gap.

It is important to note that the quantity of DA EIR procured will not necessarily be equivalent to the size of the Day-Ahead energy gap. Rather, we expect that, with the FER Demand Quantity applied, the new Day-Ahead Market will address any Day-Ahead energy gap by procuring a combination of DA EIR and additional Day-Ahead physical energy (relative to the quantity of Day-Ahead physical energy that would clear under current market rules). How the Day-Ahead market clearing engine will allocate DA EIR and additional Day-Ahead energy awards in order to satisfy the FER Demand Quantity is discussed further in Section V.B below.

Q: Can you describe the frequency and magnitude of the Day-Ahead energy gap historically?

A: Considering the recent historical period of 2019 through 2021, we observe that the Day-Ahead energy gap was 0 MWh in approximately 50 percent of hours. In such hours, the FER Demand Quantity would not be impactful, and no DA EIR or additional physical Day-Ahead energy would clear due to its application. In the other 50 percent of hours, we observe a non-zero Day-Ahead energy gap. In such hours, we would expect the Day-Ahead Market to procure a combination of DA EIR and additional physical Day-Ahead energy in order to close that gap. In such hours, the median observed historical Day-Ahead energy gap is approximately 300 MWh.

The Day-Ahead energy gap for each hour of 2019 through 2021 is charted in the graph below. Non-zero values in this figure represent hours in which the aggregate Day-Ahead cleared physical supply is less than the ISO's load forecast. In the 50 percent of hours in which the Day-Ahead cleared physical supply equals or exceeds the load forecast, the Day-Ahead energy gap is represented with a value of zero in the figure below.



Q: How will the FER Demand Quantity be reflected in the proposed Day-Ahead Market?

A: The FER Demand Quantity will be reflected in the FER constraint. This constraint is formulated as follows.

- Day-Ahead energy awards of Generator Assets, DRRs, and imports + DA EIR awards ≥ FER Demand Quantity + Day-Ahead energy awards of exports

The constraint means that the combined Day-Ahead physical energy supply and EIR awards are greater than or equal to the combined load forecast and cleared exports in the Day-Ahead Energy Market.

Similar to the constraints for Day-Ahead Flexible Response Services, a penalty factor is considered in this constraint that will reflect the maximum cost the region is willing to incur in order to procure either additional energy or DA EIR to satisfy that constraint (*i.e.,* the FER Penalty Factor discussed further below).

IV. <u>ELIGIBILITY TO PARTICIPATE IN DAY-AHEAD ANCILLARY SERVICES MARKET</u>

Q: Which resources are eligible to offer and receive an award for Day-Ahead Ancillary Services?

A: To be eligible to offer and receive an award for Day-Ahead Ancillary Services, a seller's offer must be associated with a physical resource located within the New England Control Area, have an open offer to provide or consume energy for the hour associated with the Day-Ahead Ancillary Services Offer, and meet the additional eligibility criteria for at least one of the four products. Such resources include Generator Assets with open Supply Offers, DRRs with open Demand Reduction Offers, and Dispatchable Asset Related Demands ("DARDs") with open Demand Bids. The existence of an open Supply Offer, Demand Reduction Offer, or Demand Bid is necessary because such offers contain information regarding a resource's physical capabilities (*i.e.*, maximum output, ramp rate, etc.) that are necessary for determining its ancillary service capabilities. Generally, these represent the set of resources that the ISO may call upon in Real-Time in order to satisfy the load forecast, or to respond to a contingency. Imports and Increment Offers are not eligible to provide Day-Ahead Ancillary Services.

Q: Which Day-Ahead Ancillary Service products can Generator Assets and DRRs offer and be awarded?

A: Generator Assets and DRRs may provide offers for all four Day-Ahead Ancillary Services Offers products: DA TMSR, DA TMNSR, DA TMOR, and DA EIR. These resources can be called upon in Real-Time to help to satisfy the load forecast, or to respond to a contingency.

Q: Which Day-Ahead Ancillary Service products can DARDs offer and be awarded?

A: DARDs may provide offers for two of the four Day-Ahead Ancillary Services products: DA TMSR and DA TMOR.[8] Just as in Real-Time operations, a DARD must be consuming energy in order to provide reserves. This is because the consumption can then be reduced if needed in order to respond to a contingency. Because a DARD must be consuming to provide this reserve capability, it can only be awarded those Day-Ahead Ancillary Services products that can be provided from an online state. This includes DA TMSR and DA TMOR, but

[8] A DARD is demand associated with an asset that can modify its energy consumption in response to dispatch instructions, in Real-Time. DARDs in the ISO NE Control Area include the consumption side of pumped storage hydro facilities and grid-connected batteries.

excludes DA TMNSR (which can only be provided by fast-start resources in an offline state).

In addition, DARDs are not able to offer, or be awarded, DA EIR. Recall that DA EIR is intended to contribute to satisfying the ISO's next-day load forecast, as reflected in the FER Demand Quantity. Importantly, the ISO's load forecast does not include DARD consumption. As a result, a DARD cannot contribute to satisfying that load forecast by reducing its consumption. For this reason, DARD's do not participate in satisfying the FER Demand Quantity, and they cannot provide DA EIR.

Q: What eligibility criteria exist for resources to be able to be awarded the Day-Ahead Flexible Response Services products?

A: Day-Ahead Flexible Response Services products are procured to position the system to be able to respond to a contingency in Real-Time. As a result, the ISO proposes to apply the same set of eligibility criteria for Day-Ahead Flexible Response Services products as is applied today for designating Real-Time Operating Reserves. These criteria include the requirements that the resource be dispatchable, located within the New England Control Area, capable of receiving electronic dispatch instructions, and not be constrained by transmission limitations, among others. For a complete set of criteria, see Section III.1.7.19.1 of Market Rule 1 of the Tariff.

Q: What eligibility criteria exist for resources to be able to be awarded the DA EIR product?

A: In order to receive a DA EIR award, Generator Assets and DRRs must either (1) be scheduled for energy within the hour of the DA EIR award, or (2) be fast-start resources, which pursuant to the Tariff are resources with combined notification and start-up times that do not exceed thirty minutes and Minimum Run Times and Minimum Down Times that do not exceed one hour.[9] Thus, a non-fast-start Generator Asset that is scheduled in the Day-Ahead Market to be offline during a given hour of the Operating Day will not be eligible to provide DA EIR for that hour.

The requirement that non-fast-start resources also be scheduled for energy in order to provide DA EIR reflects a technical limitation of the Day-Ahead market clearing engine. In order to allow such resources to provide DA EIR from an offline state, the clearing engine would need to consider an additional binary commitment variable for each such resource and for each hour of the Operating Day, in order to properly evaluate each resource's intertemporal parameters.[10] Including these additional binary commitment variables would dramatically increase the size of the commitment problem that the market clearing engine must

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[9] See the definitions of Fast Start Generator and Fast Start Demand Response Resource in Section I.2.2 of the Tariff. To qualify as a fast-start resource, generators and DRRs must meet certain other criteria as well.

[10] Intertemporal parameters include runtimes, downtimes, reduction times (in the case of DRR), notification times, and start-up times.

solve each day, and raises concerns regarding the ability of the ISO to run the Day-Ahead Market within required timeframes. In addition, we expect that minimal benefit would be derived as a result of extending the ability to provide "offline" DA EIR to non-fast-start resources. As discussed further in Section V.B, our expectation of long-run market equilibrium is that load will have stronger incentive to fully participate in the Day-Ahead Market with the FER Demand Quantity applied, and, as a result of this increased load participation, the Day-Ahead energy gap will be addressed primarily by clearing additional physical Day-Ahead energy supply, driving the cleared quantity of DA EIR toward zero. The additional risks associated with including the additional binary commitment variables required in order to enable the clearing of DA EIR on offline, non-fast-start resources outweigh any benefit, especially in the long-run, from doing so.

In addition to the criteria above, Generator Assets and DRRs may not clear DA EIR if they are constrained by transmission limitations. This criteria is intended to ensure that any DA EIR awarded will be deliverable as energy in Real-Time to satisfy the load forecast.

Q: Why aren't virtual transactions allowed to participate in the Day-Ahead Ancillary Services Market?

A: As discussed above, a key goal of DASI is to establish a reliable next-day operating plan through a market mechanism, positioning the system on a Day-Ahead basis to be able to meet the load forecast and Operating Reserve needs in

Real-Time. Virtual transactions, by definition, participate only in the Day-Ahead Energy Market, and cannot be called upon to deliver energy in Real-Time. While virtual transactions do provide benefits in terms of enhancing Day-Ahead Market efficiency, they cannot deliver energy in Real-Time, and therefore they cannot contribute to a reliable next-day operating plan. For this reason, they cannot participate in the Day-Ahead Ancillary Services Market.

Q: Why aren't imports allowed to offer and receive awards for Day-Ahead Ancillary Services?

A: Imports are not allowed to provide DA Flexible Response Services because imports are not eligible to provide Real-Time Operating Reserves. Because Day-Ahead Flexible Response Services are intended to set up the system with the capabilities that will be required in Real-Time, the same set of eligibility requirements that exist for Real-Time Operating Reserves are imposed for Day-Ahead Flexible Response Services.

Imports are not allowed to provide DA EIR because of the current infeasibility of coordinating such transactions with neighboring control areas. In order to be assured that DA EIR cleared on imports would be deliverable as energy in Real-Time, it would be necessary for the ISO's neighboring systems to commit their resources in a manner that would accommodate such Real-Time operation. This presents a host of practical challenges. In neighboring areas that operate markets, such as New York, the day-ahead market is cleared earlier than in New England.

This presents a problem related to the timing of information and how our neighboring area might take into account DA EIR awards cleared on imports from New York into New England. In other neighboring areas, such as Quebec, no organized markets exist, and it is not clear precisely how DA EIR awards on imports from Quebec into New England would be handled by our neighbor. The ISO knows from experience that coordination on market changes with neighboring areas takes considerable time and effort from all parties. For these reasons, at present it is not feasible to propose that DA EIR be allowed to clear on imports. We are open to future enhancements that would allow DA EIR to clear on imports, subject to working through related issues with neighboring control areas.

It is important to note that, while the DASI design does not allow DA EIR to be cleared on imports, Day-Ahead energy awards cleared by imports are considered to be deliverable in Real-Time. As a result, any Day-Ahead energy awards cleared by imports will be counted as contributing to satisfying the FER Demand Quantity. As described in Section VII below, however, imports that clear for Day-Ahead energy will be required to demonstrate a submitted corresponding Real-Time transaction to receive FER payments.

V. <u>OFFERS</u>

Q: What is a resource offering when it submits a Day-Ahead Ancillary Services Offer in the proposed Day-Ahead Market?

A: A Day-Ahead Ancillary Services Offer represents the resource's willingness to provide the Day-Ahead Ancillary Services products that it is qualified to provide at offer prices specific to a single hour of the Operating Day that follows the Day-Ahead Market.

Q: What are the requirements for a Day-Ahead Ancillary Services Offer to be considered by the ISO in the Day-Ahead Market?

A: For a Day-Ahead Ancillary Services Offer to be valid, the Market Participant must have also submitted in the Day-Ahead Market a corresponding Supply Offer, Demand Reduction Offer, or Demand Bid (if a DARD) for the same hour of the Operating Day. The Day-Ahead Ancillary Services Offer must have a single, non-negative quantity term that represents the total amount of Day-Ahead Ancillary Services the resource is willing to provide across all Day-Ahead Ancillary Services products for which it is eligible. The quantity term may not exceed the Economic Maximum Limit, Maximum Reduction, or Maximum Consumption Limit specified in the resource's energy offer. The resource may also specify as part of its offer the maximum total quantity of both Day-Ahead energy and ancillary services MWhs for which the resource is willing to accept an award in the Day-Ahead Market, which will be referred to as the Maximum Daily Award Limit.

Further, the offer must specify a non-negative price term for each of the four Day-Ahead Ancillary Services. However, in the case of resources that meet the eligibility for some but not all four of the Day-Ahead Ancillary Services products, the price terms for products that the resource is ineligible to provide will be ignored by the ISO's market clearing engine.

Q: Please explain the Maximum Daily Award Limit parameter.

A: The Maximum Daily Award Limit ("MDAL") is an optional parameter that reflects the maximum total MWh quantity of Day-Ahead energy and Day-Ahead Ancillary Services that the resource is willing to sell across all 24 hours of the Day-Ahead Market horizon. For example, if a resource submits an MDAL parameter equal to 100 MWh, then its total Day-Ahead energy awards and Day-Ahead Ancillary Services awards, across all Day-Ahead Ancillary Services products, will not exceed 100 MWh for that day. This parameter is conceptually similar to the existing Maximum Daily Energy parameter, which is used today by Limited Energy Resources[11] to limit the amount of energy they may clear across all hours of the Day-Ahead Energy Market. If no MDAL is submitted, no such limitation will be applied by the Day-Ahead market clearing engine.

Q: How do you expect the Maximum Daily Award Limit parameter will be used?

[11] A Limited Energy Resource is one that cannot operate continuously at full output on a daily basis, as defined in the Tariff, Section I.2.2, of Market Rule 1.

A: We expect that resources such as Continuous Storage Facilities and Binary Storage Facilities may use the MDAL parameter to reflect limitations on the amount of Day-Ahead energy and Day-Ahead Ancillary Services they can provide during an Operating Day as a result of their limited energy storage capability and their need to cycle in order to replenish that stored energy.[12] In addition, the MDAL parameter may be used by participants generally as a means of limiting Day-Ahead awards and the financial exposure that comes with them.

Q: Do Day-Ahead Ancillary Services Offers include specifications of physical parameters, such as Maximum Operating Limit, Ramp Rate, and CLAIM10 and CLAIM30 capability?

A: No. There is no opportunity in the Day-Ahead Ancillary Services Offer for the resource to specify or adjust its physical parameters. The physical parameters are already specified as part of the Supply Offer, Demand Reduction Offer, or Demand Bid submitted by the resource. The physical parameters submitted with such other offers will be used within the market clearing engine to limit the resource's clearance for Day-Ahead Ancillary Services to its capability to provide those products.

[12] A pumped-storage hydro resource is an example of a Binary Storage Facility. A grid-connected battery is an example of a Continuous Storage Facility.

Q: Why do Day-Ahead Ancillary Services Offers only specify a single quantity term while also specifying a price term for each of the four products?

A: The Day-Ahead market clearing engine will take this single offer quantity parameter as an input and will consider it along with the resource's physical characteristics in order to determine the most cost-effective set of Day-Ahead Ancillary Service awards (across all products) to clear. An offer will not need to specify a quantity for each product because the market clearing engine has all necessary information regarding each resource's physical capabilities (*i.e.*, ramp rate, CLAIM10/30 capability, etc.) from the resource's open energy supply offer, demand reduction offer, or demand bid and will optimally determine the set of ancillary services the resource is able to provide, taking into account the Day-Ahead Ancillary Services Offer's prices.

Q: Why may product-specific offer prices be submitted for Day-Ahead Ancillary Services products?

A: Market Participants expressed interest in the ability to submit product-specific offer prices, noting that they may take different actions in response to receiving Day-Ahead Ancillary Service obligations for different products. The ISO considered whether this request could be accommodated without raising market power concerns, and it performed simulations to study this issue. The ISO concluded that Market Participants could not increase their portfolio's overall profitability by economically withholding a single product (by offering it at an uncompetitively high price), and that therefore no market power concerns would arise from a market design that allowed product-specific offer prices for Day-Ahead Ancillary Services. As such, we have incorporated this feature into the proposed design, allowing Market Participants the flexibility to reflect potentially different avoidable costs for different Day-Ahead Ancillary Services in their Day-Ahead Ancillary Services Offers. As described in the Testimony of Parviz Alivand, Market Participants will be able to present variances in avoidable costs for the different products to the Internal Market Monitor through a consultation process if such costs are not already factored into the resource's mitigation thresholds. For clarification, participants are not required to offer a different price for each product, and may choose to offer the same price for each product.

Q: Can a single MW of resource capability clear for more than one Day-Ahead product?

A: Generally, no. For Generator Assets and DRRs, a single MW of resource capability can clear as either Day-Ahead energy or DA TMSR or DA TMNSR or DA TMOR or DA EIR. In this way, that MW of resource capability can receive an award of one MWh for only one product and is not double-counted across Day-Ahead products.[13]

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[13] While a single MW of Generator Asset or DRR capability can clear as only one product, each such cleared MW will be compensated by clearing prices that reflect its contribution to satisfying one or more of the Day-Ahead Market's constraints. See Section V.B of this testimony, and section IV.B of the testimony of Dr. Matthew White, for further details.

For DARDs, however, this is not the case. A DARD may only clear DA TMSR or DA TMOR awards in hours when it is also cleared to consume energy. This is because a DARD is able to contribute to contingency response by reducing its consumption. As a result, a cleared MWh of energy consumption on a DARD may also clear as a MWh of DA TMSR or DA TMOR.

Q: When must a Day-Ahead Ancillary Services Offer be made?

A: As with Day-Ahead energy offers, Day-Ahead Ancillary Services Offers will be due by 10:30 a.m. on the day before the Operating Day. There is no Re-Offer Period for Day-Ahead Ancillary Services Offers or other periods for re-submitting or adjusting offers.

VI. JOINTLY-OPTIMIZED MARKET CLEARING AND PRICING

Q: How will the proposed Day-Ahead Market schedule and price Day-Ahead Ancillary Services awards?

A: The market clearing engine for the proposed Day-Ahead Market will treat the scheduling of Day-Ahead energy and ancillary services as one joint market with a number of parameters and constraints that must be respected when scheduling resources to provide energy and ancillary services. Those parameters and constraints include Day-Ahead energy and ancillary services offer prices and quantities submitted by participants, the physical parameters and other limitations included in each resource's energy offers, the demand bids made by load in the Day-Ahead Market, the ISO-determined demand quantities described in Section

III above, and the energy balance constraint (which ensures cleared Day-Ahead energy supply equals cleared Day-Ahead energy demand), among other parameters and constraints necessary for proper clearing and pricing of the Day-Ahead Market. The results will be a Day-Ahead schedule of awards for both energy and ancillary services and four new clearing prices: the DA TMSR clearing price, the DA TMNSR clearing price, the DA TMOR clearing price, and the FER Price.

In considering all of these parameters and constraints, the Day-Ahead Market will determine the most efficient and cost-effective method of clearing Day-Ahead energy and ancillary services offers against demand (bid-in or ISO-determined) in a way that determines the optimal Day-Ahead schedule of commitments and awards across *all* Day-Ahead products. As explained further below, this joint optimization across all products means that the Day-Ahead Market will schedule commitments and awards in a way that recognizes the substitutability of certain products and in a way that may create cross-product opportunity costs for some resources.

A. IMPACT OF RESOURCE PARAMETERS

Q: Please elaborate on the physical parameters and other limitations in resources' energy offers that will impact the scheduling of Day-Ahead Ancillary Services awards?

A: In addition to the Day-Ahead Ancillary Services offer prices, quantity, and MDAL parameters discussed above, Generator Assets, DRRs, and DARDs eligible to submit offers and receive awards for Day-Ahead Ancillary Services Offers will receive awards consistent with their physical characteristics. The key physical characteristics, as reflected in the resource's energy offer and Offer Data, are the following:

- **Maximum operating limits**. A Generator Asset or DRR's combined Day-Ahead energy and Day-Ahead Ancillary Services awards will not exceed its Economic Maximum Limit or Maximum Reduction limit. A DARD's Maximum Consumption Limit serves as an upper bound on the quantity of Day-Ahead energy it may clear in an hour, and its Day-Ahead cleared energy quantity serves as an upper bound on the combined DA TMSR and DA TMOR awards that the DARD can receive.
- **Ramp rates**. A Generator Asset or DRR's combined Day-Ahead energy and DA EIR award in an hour must be feasible given its Day-Ahead energy award in the prior hour, based on its ramping capability over 60 minutes. If a Generator Asset, DRR, or DARD has an energy award in the hour, its DA TMSR and DA TMOR awards will be limited by its ability to ramp over ten or thirty minutes, as applicable.
- **CLAIM10/CLAIM30 capability**. Generators and DRRs that are fast-start resources and choose to establish CLAIM10 and CLAIM30 capability through the ISO's audit processes may clear certain Day-Ahead Ancillary Services in hours when they do not also have a Day-Ahead

energy award. Such resources will be limited by the lesser of the ISO-audited CLAIM10 value and the participant-offered CLAIM10 value when clearing DA TMNSR awards. Similarly, such resources will be limited by the lesser of the ISO-audited CLAIM30 value and the participant-offered CLAIM30 value when clearing DA TMOR awards. CLAIM10 and CLAIM30 values are not applicable to DARDs, which can only provide reserve capability from an online state.

Q: Please provide simple examples illustrating these limitations in practice.

A: First, consider an example for a generator. Suppose a generator has cleared 100 MWh of energy in the prior hour, and has an Economic Min of 100 MW, an Economic Max of 155 MW, and a ramp rate of 1 MW/minute. Given these physical parameters, this resource can contribute at most the following:

- 10 MWh to satisfying the DA TMSR Demand quantity, because it can ramp up 10 MW over 10 minutes.
- 10 MWh to satisfying the Day-Ahead Total Ten-Minute Reserve Demand Quantity, because it can ramp up 10 MW over 10 minutes.
- 30 MWh to satisfying the Day-Ahead Minimum Total Reserve and Day-Ahead Total Reserve Demand Quantities, because it can ramp up 30 MW over 30 minutes.
- 55 MWh to satisfying the FER Demand Quantity. Given the resource's cleared energy quantity in the prior hour (100 MWh) and Ecomax (155

MW), the most additional capability this resource can provide over a sixty minute period is 55 MWh.

Because the resource is cleared for energy, it is considered to be online and will not clear DA TMNSR. Recall also that each MW of resource capability can only clear as one Day-Ahead product. Given these limitations, one potential DA A/S clearing outcome for this resource is as follows:

- 10 MWh TMSR award;
- 20 MWh TMOR award; and
- 25 MWh EIR award.

With this clearing result, the resource's full capability of 55 MW between its Economic Min and Economic Max is allocated across Day-Ahead Ancillary Services products.

Next consider an example for a DARD. Suppose a DARD has offered a Maximum Consumption Limit of 100 MW, has cleared 100 MWh of energy in an hour, and has a ramp rate of 20 MW/minute. Given these physical parameters, this DARD can ramp down to an offline state in five minutes. Because it can ramp to an offline state in less than ten minutes, one possible clearing outcome for this resource is a DA TMSR award of 100 MWh.

Q: Is a resource's minimum operating limit a consideration when clearing Day-Ahead Ancillary Services awards?

A: No, a resource's minimum operating limit (*i.e.*, Economic Minimum Limit for Generator Assets, Minimum Reduction for DRRs, and Minimum Consumption Limit for DARDs) is not considered when clearing Day-Ahead Ancillary Services awards on resources that do not have Day-Ahead energy awards. As a result, offline fast start resources may receive Day-Ahead Ancillary Services awards in an hour that are, cumulatively, less than their minimum operating limit. There are two primary reasons for this design choice.

First, this design choice addresses potential Day-Ahead Ancillary Services price formation issues. Specifically, it eliminates the "lumpiness" of these offline fast-start resources and allows the highest cleared Day-Ahead Ancillary Services Offer to be reflected in the Day-Ahead Ancillary Services clearing price calculations. "Lumpy" resources are those with high minimum operating limits, and clearing such resources at these minimum operating limits may serve to increase supply beyond what is required and thereby depress clearing prices. Elimination of lumpiness allows the design to avoid an outcome in which Day-Ahead Ancillary Services clearing prices are depressed such that they do not cover cleared Day-Ahead Ancillary Service sellers' offer prices, and thereby avoids the need for a potentially complicated new form of Day-Ahead Ancillary Service-specific uplift calculation. This price formation logic is similar to that reflected in the ISO's fast-start pricing rules.[14]

Second, this design choice aligns with existing Real-Time reserve designation rules. Specifically, the quantity of ten- and thirty-minute reserves that the ISO will designate on an offline fast-start resource in Real-Time is a function of its CLAIM10 and CLAIM30 values. These values, in turn, are calculated by the ISO based on the resource's observed historical performance when responding to dispatch instructions, and such values can be lower than the resource's minimum operating limit.[15] The design choice to exclude minimum operating limits from consideration when clearing Day-Ahead Ancillary Services, therefore, allows the same set of offline resources that will be designated to provide TMNSR or TMOR from an offline state in Real-Time (at quantities lower than the minimum operating limit) to also clear such quantities in the Day-Ahead Ancillary Services Market.

[14] *See* Revisions to Fast-Start Pricing and Dispatch, at 8–9, *ISO New England Inc. & NEPOOL Participants Comm.*, Docket No. 15-2716-000 (filed Sept. 24, 2015) (discussing this type of price formation logic, referring to the minimum operating limit concept as "minimum output level").

[15] See Tariff, Section III.9.5.3.1 of Market Rule 1 (explaining CLAIM10 and CLAIM30 calculations).

B. JOINT OPTIMIZATION ACROSS ALL DAY-AHEAD PRODUCTS

Q: Please elaborate on how the proposed Day-Ahead Market will produce a schedule of Day-Ahead energy and ancillary service commitments and awards using joint optimization?

A: In executing the jointly-optimized market clearing process, the market clearing engine for the new Day-Ahead Market will clear sellers' priced offers against demand quantities, both bid-in (*i.e.*, energy) and ISO-derived (*i.e.*, the FER and the Day-Ahead Flexible Response Services demand quantities), and determine the competitive clearing prices and schedule energy and ancillary service awards at those clearing prices. In doing so, however, the clearing engine does not consider each product—Day-Ahead energy, the three Day-Ahead Flexible Response Services, and DA EIR—separately. Instead, the clearing engine will consider resources' offers for all Day-Ahead products simultaneously to determine the most cost-effective means of scheduling resources to satisfy bid-in demand, the load forecast, and the ancillary services demand quantities. Through this process, the Day-Ahead Market's clearing engine will produce a schedule and clearing prices by considering both opportunities for product substitution and cross-product opportunity costs experienced by Day-Ahead suppliers when both arise. This type of joint optimization across Day-Ahead products is similar to the joint optimization of the Real-Time market clearing engine across energy and Operating Reserve products, and is similar to the joint optimization process that occurs in many other regions' Day-Ahead markets.

1. Product Substitution and Related Pricing Considerations

Q: Please explain what you mean by product substitution in the context of the proposed Day-Ahead Market's clearing engine.

A: Product substitution is relevant to the jointly-optimized Day-Ahead Market's scheduling in two aspects: (1) with regard to the cascading of Day-Ahead Flexible Response Services to satisfy the Day-Ahead Flexible Response Services Demand Quantities; and (2) with regard to satisfying the FER Demand Quantity (*i.e.*, the load forecast).

Q: How does product substitution factor into satisfying the Day-Ahead Flexible Response Services Demand Quantities?

A: The clearing engine will substitute one Day-Ahead Flexible Response Services product for another when both can satisfy the same demand quantity and the first is more cost effective. For example, as described above, both the DA TMSR and DA TMNSR products can satisfy the Day-Ahead Total Ten-Minute Reserve Demand Quantity. The market clearing engine may find it most cost effective to substitute cheaper DA TMSR for more expensive DA TMNSR when satisfying this demand quantity. This product substitution is consistent with the cascading of the Day-Ahead Flexible Response Services products to satisfy the constraints reflecting the Day-Ahead Flexible Response Services Demand Quantities. Again, as noted above, this is the same dynamic that is in effect for existing Real-Time Operating Reserve products and related constraints.

Q: How does this cascading impact the pricing of such products?

A: Day-Ahead Flexible Response Services clearing prices will be determined using standard marginal cost pricing principles, and will be calculated as the sum of the shadow prices of the constraints they contribute to satisfying, in accordance with the participation payment principle.

For background, standard marginal cost pricing principles dictate that each clearing price will reflect the value that a product provides to the system by obviating the need to procure another, more costly MWh at the margin in order to satisfy a constraint's demand quantity. The constraint associated with each demand quantity—which, in the case of the proposed Day-Ahead Market, reflects one of the region's reliability requirements—is assigned a "shadow price" in accordance with this value. Namely, the constraint's shadow price reflects the cost, in $/MWh, that would be incurred by the system to satisfy one additional MWh of product to satisfy that demand quantity.

These shadow prices are used to determine final clearing prices according to what we call "participation payment principle." The participation payment principle dictates that a product must be paid the shadow price of each constraint that it contributes to (*i.e.*, participates in) satisfying, because these shadow prices are the value that the product provides to the system at the margin by satisfying that constraint. Clearing prices for each product, in turn, are composed of the sum of one or more of these shadow prices, and they reflect the participation payment principle.

Q: Please elaborate further on how the proposed Day-Ahead Flexible Response Services product clearing prices are composed of the shadow prices calculated for each constraint.

A: Because DA TMSR is able to contribute to satisfying all four of the Day-Ahead Flexible Response Services Demand Quantities, the DA TMSR clearing price, paid to resources with DA TMSR awards, will be the sum of the shadow prices associated with all four Day-Ahead Flexible Response Services Demand Quantities. Thus, the DA TMSR clearing price reflects the sum of the shadow prices of the Day-Ahead TMSR constraint (reflecting the DA TMSR Demand Quantity), the Day-Ahead total ten-minute reserve constraint (reflecting the Day-Ahead Total Ten Minute Reserve Demand Quantity) and the Day-Ahead total thirty-minute reserve constraints (reflecting the Day-ahead Minimum Total Reserve Demand Quantity and the Day-Ahead Total Reserve Demand Quantity).

Similarly, because DA TMNSR can satisfy three of the four Day-Ahead Flexible Response Services Demand Quantities, the DA TMNSR clearing price, paid to resources with DA TMNSR awards, reflects the sum of the shadow prices of the Day-Ahead total ten-minute reserve constraint (reflecting the Day-Ahead Total Ten Minute Reserve Demand Quantity) and the Day-Ahead total thirty-minute reserve constraints (reflecting the Day-Ahead Minimum Total Reserve Demand Quantity and Day-Ahead Total Reserve Demand Quantity).

Finally, the DA TMOR clearing price, paid to resources with DA TMOR awards, reflects the sum of the shadow prices of the Day-Ahead total thirty-minute reserve constraints (reflecting the Day-Ahead Minimum Total Reserve Demand Quantity and Day-Ahead Total Reserve Demand Quantity). In this fashion, the clearing prices reflect the "cascading up" from the slower-ramping products to the faster-ramping products. This is the same familiar price cascading dynamic that exists in Real-Time Operating Reserve pricing mechanics today.

Q: Please provide a simple example of this Day-Ahead Flexible Response Services clearing price calculation logic.

A: Consider a single hour in which the ISO established Day-Ahead Flexible Response Services Demand Quantities as follows:

- DA TMSR Demand Quantity = 1 MWh;
- Day-Ahead Total Ten Minute Reserve Demand Quantity = 2 MWh; and
- Day-Ahead Minimum Total Reserve Demand Quantity = Total Reserve Demand Quantity = 3 MWh.

Suppose further that the ISO can choose from among three offers to satisfy these demand quantities:

- Generator A: a generator cleared for energy, offering its ancillary service capability at $7/MWh;
- Generator B: an offline generator with 10-minute response capability, offering its ancillary service capability at $5/MWh; and
- Generator C: an offline generator with 30-minute response capability, offering its ancillary service capability at $1/MWh.

The efficient clearing of Day-Ahead Flexible Response Services products, given these demand quantities and ancillary service offers, is as follows:

- Gen A clears 1 MWh DA TMSR;
- Gen B clears 1 MWh DA TMNSR; and
- Gen C clears 1 MWh DA TMOR.

To determine clearing prices, we must first determine the shadow prices of each Day-Ahead Flexible Response Services constraint. Working backwards—that is, "cascading up" from the slower-ramping products to the faster-ramping products—the resulting prices are as follows.

- To most efficiently satisfy another MWh of the Day-Ahead Total Reserve Demand Quantity, the system would procure an additional MWh of DA

TMOR from Generator C, at an incremental cost of $1/MWh. Therefore, the shadow price of the total 30-minute reserve constraint[16] is **$1/MWh**.

- To most efficiently satisfy another MWh of the Day-Ahead Total Ten-Minute Reserve Demand Quantity, the system would procure an additional MWh of DA TMNSR from Generator B. However, doing so would mean that the system could also procure one less MWh of TMOR from Generator C (as DA TMNSR is capable of simultaneously satisfying both the Day-Ahead Total Ten Minute and Total Reserve Demand Quantities). Therefore, the shadow price of the total ten-minute reserve constraint reflects an incremental cost of $5/MWh and an incremental savings of $1/MWh. The shadow price of the total ten-minute reserve constraint is **$4/MWh.**
- To most efficiently satisfy another MWh of the DA TMSR Demand Quantity, the system would procure an additional MWh of TMSR from Generator A. However, doing so would mean that the system could also procure one less MWh of DA TMNSR from Generator B (as TMSR is capable of simultaneously satisfying both Day-Ahead Total Ten Minute and TMSR Demand Quantities). Therefore, the shadow price of the TMSR reserve constraint reflects an incremental cost of $7/MWh and an

[16] For the purposes of this simple example, the Minimum Total Reserve Demand Quantity is set equivalent to the Total Reserve Demand Quantity. As a result, there is only a single thirty-minute reserve requirement in effect.

incremental savings of \$5/MWh. The shadow price of the DA TMSR reserve constraint is **\$2/MWh.**

Now, we can use these shadow prices to determine clearing prices for each Day-Ahead Flexible Response Services product, according to the participation payment principle described above.

- DA TMSR Clearing Price = \$1/MWh + \$4/MWh + \$2/MWh = \$7/MWh
- DA TMNSR Clearing Price = \$1/MWh + \$4/MWh = \$5/MWh
- DA TMOR Clearing Price = \$1/MWh

In this manner, all Day-Ahead Flexible Response Services products are paid a clearing price commensurate with the value they provide the system based upon the constraints they are able to satisfy. Importantly, these clearing prices also ensure sellers of Day-Ahead Ancillary Services are paid (at least) their offer price for the service they are cleared to provide. Note that in this example, no resource incurs a cross-product opportunity cost, and as such these opportunity costs do not factor into clearing price calculations here. The impact of cross-product opportunity costs is discussed in subsection 2 below.

Q: How does product substitution factor into satisfying the FER Demand Quantity?

A: The market clearing engine has two choices for satisfying FER Demand Quantity in an hour with a Day-Ahead energy gap. It can procure additional DA EIR, or it can procure additional Day-Ahead energy from physical supply resources. In order to also ensure that cleared energy supply and cleared bid-in energy demand balance, the clearing engine must also clear an equivalent amount of additional bid-in energy demand when clearing additional energy from a physical supply resource. In making these determinations, the clearing engine will select the mix of DA EIR and energy from physical supply resources that is optimal given the offered costs of DA EIR and Day-Ahead energy supply, as well as the willingness to pay represented in Day-Ahead energy demand bids.

Q: Please provide a simple example to illustrate this concept.

A: Suppose that in a given hour there exists a one MWh Day-Ahead energy gap. That is, suppose that under current market rules the Day-Ahead Energy Market would procure physical energy supply that is, in aggregate, one MWh less than the load forecast for that hour. Suppose further that the clearing engine will consider the following three offers when evaluating how to resolve this Day-Ahead energy gap once the FER Demand Quantity is applied:

- one MWh of DA EIR, offered at $3/MWh;
- one MWh of Day-Ahead energy supply from a physical supply resource, offered at $51/MWh; and
- one MWh of Day-Ahead energy demand, bid with a willingness-to-pay of $49/MWh.

As noted above, the clearing engine will choose the most cost-effective means of closing this one MWh energy gap. In doing so, it will have to consider the relative costs and benefits of procuring either DA EIR for a total cost of $3 or an additional MWh of energy supply at $51.

In terms of satisfying the one additional MWh of FER Demand Quantity caused by the one MWh energy gap in the example, both options provide the exact same benefit. Because the *only* benefit gained by the region when it procures DA EIR is the value of satisfying the FER Demand Quantity, the net cost of procuring DA EIR compared to procuring Day-Ahead energy in this example is $3.

The value of satisfying the FER Demand Quantity, however, is *not* the only benefit of procuring an additional MWh of Day-Ahead energy in this example. Procuring an additional MWh of Day-Ahead energy here also satisfies the next MWh of bid-in Day-Ahead energy demand, yielding a benefit of $49. Consequently, the net cost to the region of procuring an additional MWh of Day-Ahead energy, relative to procuring DA EIR, in this example is $2 ($51 minus $49). Viewing the relative cost of both products, the market clearing engine will choose the additional MWh of Day-Ahead energy to satisfy the remaining MWh of FER Demand Quantity because the cost (net of the additional benefit of satisfying an additional MWh of bid-in energy demand) is $2, compared to the $3 net cost of DA EIR. In this way, the market clearing engine will maximize social welfare while also satisfying the FER Demand Quantity.

If the offer prices were different, a different set of awards could result. Consider, for instance, if the MWh of DA EIR were offered at \$1/MWh, rather than \$3/MWh. In this case, the clearing engine will clear the one MWh of DA EIR, and will not clear the additional energy supply and energy demand. This is because, given its low \$1/MWh offer, DA EIR is a more cost-effective means (taking into account both the relative costs and benefits to the region of both products) of closing the Day-Ahead energy gap than clearing additional energy supply and energy demand.

Q: How does this consideration of both products ultimately impact Day-Ahead LMPs and the FER Price?

A: As discussed with the Day-Ahead Flexible Response Services, prices are efficiently set at the point at which the marginal costs of supply are equal to the marginal benefits of satisfying demand, in accordance with standard marginal cost pricing principles. With these DASI changes, there will be two distinct sets of demand that must be satisfied: bid-in energy demand, submitted by market participants, and the FER Demand Quantity, established by the ISO. The Day-Ahead LMP will reflect the marginal benefit of satisfying the next MWh of bid-in demand, while the FER Price will reflect the incremental marginal benefit of also satisfying the FER Demand Quantity.

Q: Which Day-Ahead products will be paid the FER Price?

A: Day-Ahead energy awards to physical supply resources (Generator Assets, DRRs, and imports) will be paid the FER Price, as will DA EIR awards.[17] Each of these awards contributes to satisfying the FER Demand Quantity, and as a result each of these awards receives the FER Price, following the participation payment principle.

Notably, the combination of the Day-Ahead LMP and the FER Price will cover the marginal cost of physical energy supply. Because Day-Ahead cleared suppliers of physical energy are paid both the Day-Ahead LMP and the FER Price, the offered costs of the supplier on the margin will be covered by the sum of these two clearing prices. At a high level, this is a simple application of the participation payment principle. To provide correct compensation, a resource must be paid the price for each system demand quantity (*i.e.,* constraint) that its supply helps to satisfy.

Q: Because Day-Ahead energy and DA EIR both contribute to satisfying the FER, does the ISO expect that prices between the two will be similar?

A: No. At least in the near-term, the ISO anticipates that the marginal, and therefore price-setting, resources in the Day-Ahead Energy Market will remain largely the same, and that Day-Ahead LMPs will remain in the same range as they are today

[17] Day-ahead cleared imports must meet certain additional conditions in order to receive the FER Price. See Section VII for details.

and continue to reflect the costs to produce energy of those marginal resources. The costs to provide Day-Ahead Ancillary Services, for the resources that will likely be marginal for those four products, will be much smaller. As explained in the Testimony of Parviz Alivand, the cost to provide Day-Ahead Ancillary Services includes the expected close-out charge and, for natural-gas fired resources and storage resources, the Day-Ahead cost to procure fuel or an energy charge. Where Day-Ahead procurement of fuel or an energy charge is a cost, those costs are mitigated by the potential for the resource to either resell the fuel or discharge stored energy during a different hour, mitigating the upfront cost of such procurement. Consequently, competitive Day-Ahead Ancillary Services Offers will not incorporate the same level of cost as competitive Day-Ahead energy offers, and the ISO expects prices to be much lower, based on this logic and its simulations of the Day-Ahead Ancillary Services Market for Day-Ahead Ancillary Services clearing. Representative prices are described further in Section IX, which discusses the ISO's Impact Assessment.

Q: Please provide an example of the Day-Ahead LMP and FER Price calculations you described above.

A: Consider the simple example above. First, assume that, under current market rules, offered energy supply intersects bid-in energy demand at $50/MWh. Therefore, under current market rules, the Day-Ahead LMP in this hour would be $50/MWh.

Now, consider how the Day-Ahead LMP and FER Price would be determined with the FER Demand Quantity also in effect. In this example with the FER Demand Quantity applied, there exists a one MWh Day-Ahead energy gap, which the clearing engine addresses by procuring one MWh of additional energy supply at an offer of $51/MWh and clearing one MWh of additional bid-in energy demand at a bid of $49/MWh. In this case, the marginal benefit of serving bid-in energy demand is $49/MWh. All buyers of energy in the Day-Ahead Market are willing to pay at least $49/MWh for energy. As a result, the Day-Ahead LMP in this simple example is $49/MWh. The marginal benefit of also satisfying the FER Demand Quantity is reflected by the additional cost the system must incur to satisfy that quantity: specifically, $2/MWh ($51 minus $49). As a result, the FER Price in this simple example is $2/MWh. Taken together, Day-Ahead LMP plus FER Price equals $51/MWh, which is reflective of the marginal supplier's incremental cost of energy. It is important to note that the Day-Ahead LMP in this example is lower than it would be under current market rules ($49/MWh < $50/MWh), while the total compensation to physical suppliers of energy is higher than it would be under current market rules ($51/MWh > $50/MWh).

Q: Given this pricing dynamic, is the application of the FER Demand Quantity expected to decrease convergence between Day-Ahead LMPs and Real-Time LMPs?

A: No, we expect that Day-Ahead LMPs will continue to converge with expected Real-Time LMPs. This is because the application of the FER constraint will strengthen the incentive for demand to participate in the Day-Ahead Market, as a direct result of the pricing dynamic noted above.

Q: Please explain how the application of the FER Demand Quantity will strengthen the incentive for demand to participate in the Day-Ahead Market.

A: With the FER constraint applied in the Day-Ahead Market, there is potential for the Day-Ahead LMP to be lower than it would be under current market rules in hours with a Day-Ahead energy gap. This is evident in the simple pricing example above, in which the Day-Ahead LMP is \$50/MWh under current market rules, but is \$49/MWh when the FER constraint is applied. This lower Day-Ahead LMP pricing outcome, however, relies upon Day-Ahead demand submitting the same demand bids regardless of whether or not the FER constraint is applied, and is not reflective of a long-term equilibrium condition. Rather, we expect that Day-Ahead demand would instead increase its energy purchases in the Day-Ahead Market, in order to take advantage of the lower Day-Ahead LMP. In this way, we expect increased demand participation in the Day-Ahead market will "compete away" any difference between the Day-Ahead LMP and expected Real-Time LMPs. The expected long-term equilibrium, therefore, is that Day-Ahead LMPs will continue to converge with expected Real-Time LMPs with the proposed Day-Ahead Market in place, as they do today.

For clarification, despite the potential for a decrease in Day-Ahead LMPs, the ISO anticipates compensation for Day-Ahead physical energy supply will increase because that compensation will include both the Day-Ahead LMP and the FER Price. Demand will pay the FER Price regardless of whether it clears its load in the Day-Ahead Energy Market because, as described in Section VII, the costs of satisfying the FER are allocated based on Real-Time Load Obligations. Consequently, despite any overall increase in Day-Ahead energy compensation, demand is expected to respond to the potential for lower Day-Ahead LMPs.

2. Cross-Product Opportunity Costs

Q: Please explain cross-product opportunity costs.

A: A cross-product opportunity cost is incurred when a resource would be financially better off providing one product, but is instead dispatched or cleared by the ISO to provide another product because such a clearing results in the most economically efficient solution. In such cases, ISO pricing calculations provide compensation for these opportunity costs, in order to ensure that resources have an economic incentive to follow the ISO's dispatch or clearing and to bid at their marginal costs for each of the Day-Ahead products. The Day-Ahead Market's clearing engine will generate clearing prices that incorporate both the marginal supply offer for the Day-Ahead product and cross-product opportunity costs.

The ISO's existing Real-Time reserve market provides a ready example of such cross-product opportunity costs. In certain circumstances, the ISO may "re-dispatch" the system in Real-Time to create required Real-Time Operating Reserves. Such reserves are typically created by dispatching down a lower-cost resource while dispatching up a higher-cost cost resource, actions which may serve to increase the Real-Time LMP. In such cases, the lower-cost resource incurs a cross-product opportunity cost by providing Operating Reserve instead of energy. To address this issue and ensure the lower-cost resource has incentive to follow ISO dispatch instructions, the lower-cost resource is paid (at least) its cross-product opportunity cost in the form of the Real-Time reserve clearing price.

Q: Why is recognizing cross-product opportunity costs a necessary component of creating an efficient market?

A: If cross-product opportunity costs were not reflected in clearing prices, then the awards and clearing prices produced by the ISO will not align with a resource's private incentives. This, in turn, would create perverse incentives for resources to seek to avoid receiving awards for products that they can most efficiently and cost effectively provide, and instead pursue awards for products that offer greater profit. By incorporating cross-product opportunity costs into clearing prices, such perverse incentives are eliminated.

Q: How does the clearing engine's consideration of cross-product opportunity costs impact the scheduling of Day-Ahead energy and Day-Ahead Ancillary Services awards?

A: The market clearing engine for the proposed Day-Ahead Market, when considering all forms of Day-Ahead supply offers and demand (*i.e.*, including both bid-in energy demand and the ISO-determined demand quantities discussed above), may find that it is most efficient to clear a resource for one product instead of another, even in a circumstance where the resource is infra-marginal for the second product and where the second product would provide greater profit than the first. Clearing the resource for the first rather than the second product in that case causes the resource to incur an opportunity cost. In pricing the two products, the Day-Ahead market clearing engine will incorporate this opportunity cost into the clearing prices. As stated above, this is very similar to the example of how cross-product opportunity costs are reflected in the price of Real-Time Operating Reserves under current market rules. As a consequence, Day-Ahead Market clearing prices will reflect two components: the supply offer of the marginal resource to provide that product; and cross-product opportunity costs incurred as a result of the efficient market clearing, if any.

For example, just as in Real-Time, a resource may clear a Day-Ahead Flexible Response Services award when it might more profitably provide Day-Ahead energy. In such a case, its opportunity cost of providing the Day-Ahead Flexible Response Services product rather than energy will be accounted for in the Day-Ahead Flexible Response Services product's clearing price. Conversely, a resource could most efficiently clear an energy award, when it might more profitably provide a Day-Ahead Flexible Response Services product. In such a case, the Day-Ahead LMP or the FER Price will reflect the resource's opportunity cost of providing energy rather than the Day-Ahead Flexible Response Service product.[18]

The key takeaway is this: the pricing calculations performed by the market clearing engine naturally reflect these cross-product opportunity costs, and ensure that those opportunity costs are compensated by clearing prices. Importantly, the awards and clearing prices produced by the clearing engine, with consideration of these cross-product opportunity costs, are intended to achieve the most efficient and cost effective allocation of Day-Ahead resource capabilities.

Q: Can you provide a simple example of such cross-product opportunity costs and their pricing impacts?

A: Yes. Consider a simple case in which the market clearing engine must clear supply to satisfy the last MWh of the Day-Ahead Total Ten Minute Reserve Demand Quantity, and it has two resources available for doing so. Assume the Day-Ahead LMP is $34/MWh.

- Online Resource A has an energy offer price of $30/MWh, and a DA TMSR offer price of $3/MWh.
- Offline Fast Start Resource B has a DA TMNSR offer of $8/MWh.

[18] Numerical clearing and pricing examples, including numerical illustrations of these types of cross-product opportunity costs and how they factor into Day-Ahead Market price, were provided to stakeholders. *See* ISO-NE Presentation to NEPOOL Markets Committee, *Day-Ahead Ancillary Services Initiative (DASI)*, at Appendix 2, 71–89 (Jan. 10, 2023), *available at* https://www.iso-ne.com/static-assets/documents/2023/01/a03a_mc_2023_01_10-12_dasi_presentation.pptx.

The market clearing engine can choose to "dispatch down" Resource A in order to clear one additional MWh of DA TMSR, and thereby satisfy the Day-Ahead Total Ten Minute Reserve Demand Quantity. If it does so, Resource A's DA TMSR will be procured at its offered cost of $3/MWh, and Resource A will incur a $4/MWh opportunity cost associated with providing DA TMSR rather than Day-Ahead energy ($34/MWh DA LMP minus $30/MWh energy offer equals $4/MWh).

Alternatively, the market clearing engine can choose to procure one MWh of DA TMNSR from Resource B to satisfy the Day-Ahead Total Ten Minute Reserve Demand Quantity. If it does so, Resource B's DA TMNSR will be procured at its offered cost of $8/MWh. In this case, the market clearing engine will opt to procure one MWh of DA TMSR from Resource A to satisfy the Day-Ahead Total Ten-Minute Reserve Demand Quantity. As discussed above, clearing price calculations will consider both Resource A's Day-Ahead Ancillary Services Offer price for DA TMSR ($3/MWh), as well as its opportunity cost of not providing energy ($4/MWh). As a result, the DA TMSR clearing price will be $7/MWh. This is a more efficient and less costly solution than procuring one MWh of DA TMNSR from Resource B, which would result in its $8/MWh offer cost being reflected in clearing price calculations.

C. APPLICATION OF PENALTY FACTORS

Q: How will the new Day-Ahead Market address circumstances where the Day-Ahead Market is unable to satisfy the Day-Ahead reserve demand quantities and FER?

A: Similar to what occurs in Real-Time today, the ISO is adopting Reserve Constraint Penalty Factors ("RCPFs") that are applicable to the Day-Ahead Flexible Response Services Demand Quantities. These RCPFs are reflected in pricing calculations when the Day-Ahead Market is deficient in ten or thirty-minute reserves. In this context, an RCPF is effectively the maximum cost the region is willing to incur to satisfy a Day-Ahead Flexible Response Services Demand Quantity. If the cost to satisfy the Day-Ahead Flexible Response Services requirement exceeds the RCPF, the clearing engine will no longer satisfy that demand quantity, and the system will instead become deficient in reserves. In such cases, this penalty price will be reflected in the applicable clearing prices of Day-Ahead products, following standard marginal cost pricing logic. Identical to how the RCPFs function for Real-Time reserves, the RCPFs applied in the Day-Ahead also serve to limit the maximum possible clearing prices that may be produced for the Day-Ahead Flexible Response Services products, again following standard marginal cost pricing logic.

The ISO is also adopting the FER Penalty Factor, which establishes the maximum cost the region is willing to incur to satisfy the FER Demand Quantity. If the cost to satisfy the FER Demand Quantity exceeds the FER Penalty Factor, the clearing engine will no longer satisfy that demand quantity, and the system will procure less physical supply capability than the load forecast. Again, in such cases this penalty price will be reflected in applicable clearing price calculations, and will establish the maximum possible FER Price, following standard marginal cost pricing logic.

Q: What are the RCPFs that the ISO is adopting for its Day-Ahead Flexible Response Service Demand Quantities, and how are they applied?

A: The Day-Ahead Flexible Response Services Demand Quantity RCPFs are set at the same values as the analogous existing Real-Time Operating Reserve RCPF values, as follows.

- DA TMSR Demand Quantity RCPF = $50/MWh
- DA Total Ten-Minute Reserve Demand Quantity RCPF = $1,500/MWh
- DA Minimum Total Reserve Demand Quantity RCPF = $1,000/MWh
- DA Total Reserve Demand Quantity RCPF = $250/MWh

As noted above, a Day-Ahead Flexible Response Services RCPF will be applied in pricing calculations in the event that the associated demand quantity cannot be satisfied at an incremental cost less than or equal to the RCPF. The RCPF will set the shadow price of the violated constraint, and will affect all relevant product clearing prices based upon the standard pricing calculations discussed above.

Consider, for example, a case in which there is insufficient ancillary services supply capability offered to satisfy the DA TMSR Demand Quantity. In this case, the shadow price of the associated constraint would be set at the RCPF value of \$50/MWh. The only Day-Ahead Flexible Response Services product whose clearing price is affected by this constraint's shadow price is the DA TMSR product, because only the DA TMSR product can contribute to satisfying the DA TMSR Demand Quantity. Following standard clearing price calculation logic, the clearing price of DA TMSR would reflect this \$50/MWh RCPF, plus the shadow price of the Day-Ahead total ten-minute reserve constraint (reflecting the Day-Ahead Total Ten-Minute Reserve Demand Quantity), plus the shadow price of the thirty-minute reserve constraints (reflecting the Day-Ahead Minimum Total Reserve Demand Quantity and Day-Ahead Total Reserve Demand Quantity).

Q: Can these Day-Ahead Flexible Response Services RCPFs also play a role in Day-Ahead LMP and FER Price calculations?

A: Yes. Consider the Day-Ahead LMP, for example. This price represents the cost that would be incurred at the margin to satisfy another MWh of bid-in energy demand. Consider an hour in which the physical energy supply procured well exceeds the load forecast (and so the FER price equals \$0/MWh), but the system is short of DA TMSR (and so the RCPF of \$50/MWh is in effect). The cost at the margin to satisfy an increment of bid-in energy demand will reflect the cost to dispatch the marginal resource up for one additional MWh of energy, as well as the \$50/MWh penalty price incurred when this re-dispatch worsens the DA TMSR deficiency by one additional MWh. In such a case, the DA TMSR RCPF is incorporated within, and serves as an "adder" to, the Day-Ahead LMP. This same logic applies to Real-Time LMPs during periods of Operating Reserve scarcity today. A similar dynamic can play out with the FER Price calculation in hours in which a Day-Ahead energy gap exists.

Q: Why has the ISO chosen the same RCPFs as those used in Real-Time?

A: Setting the Day-Ahead Flexible Response Services RCPFs equivalent to their Real-Time Operating Reserve analogs ensures consistency across the Day-Ahead and Real-Time markets. In the unlikely event that reserve scarcity were expected in both the Day-Ahead and Real-Time markets, maintaining consistency of these RCPF values means that participants will face consistent payment and charge rates for Day-Ahead and Real-Time energy. If these RCPFs were set differently from each other, perverse participation incentives would be in effect in the event that Day-Ahead and Real-Time scarcity were expected. Suppliers would have incentive to sell energy only in the market with the higher RCPFs, while load would have incentive to purchase energy only in the market with the lower RCPFs. Maintaining consistent RCPFs across markets addresses this concern.

Q: What is the FER Penalty Factor, and how is it applied?

A: The FER Penalty Factor is $2,575/MWh. As noted above, this is the maximum price the region is willing to pay to satisfy the FER Demand Quantity. If the cost to satisfy the FER Demand Quantity exceeds $2,575/MWh, or if insufficient supply exists, the clearing engine will no longer satisfy that Demand Quantity and the system will procure less physical supply capability than the load forecast. In such circumstances, this penalty factor will set the FER Price at $2,575/MWh.

Q: Why has the ISO chosen this FER Penalty Factor?

A: This value of $2,575/MWh was selected in order to ensure the market clearing engine prioritizes satisfying the FER Demand Quantity above satisfying the Day-Ahead Flexible Response Services Demand Quantities. This reflects the operational reality that, in the event that supply is scarce, the ISO will prioritize serving load above satisfying its Operating Reserve requirements. The value of $2,575/MWh was selected to be slightly greater than the sum of the RCPFs associated with the Day-Ahead TMSR Demand Quantity ($50/MWh), the Day-Ahead Total Ten-Minute Reserve Demand Quantity ($1,500/MWh), and the Day-Ahead Minimum Total Reserve Demand Quantity ($1,000/MWh). Specifically, this value is set at (approximately) 101 percent of this sum of $2,550/MWh. By setting this penalty factor at a level higher than the aggregate Day-Ahead Flexible Response Services Demand Quantity RCPFs, we ensure that a violation of the FER Demand Quantity is more costly than simultaneous violations of the Day-Ahead Flexible Response Services Demand Quantities. As a result, the market clearing engine will prioritize satisfying the FER Demand Quantity over satisfying those Day-Ahead Flexible Response Services Demand Quantities.

VII. <u>SETTLEMENTS AND COST ALLOCATION</u>

Q: How will the ISO settle Day-Ahead Ancillary Services awards?

A: After the Operating Day associated with the Day-Ahead Ancillary Services awards, the ISO will settle Day-Ahead Ancillary Services sellers' positions by crediting the seller with the MWh quantity of each Day-Ahead Ancillary Services product provided as part of the award, multiplied by the appropriate clearing price. As indicated above, for DA EIR awards, the appropriate clearing price is the FER Price. The seller will then be charged any close-out charge, which will be calculated by multiplying the combined MWh of the Day-Ahead Ancillary Services awards for all products by the greater of (1) the difference between the Real-Time Hub Price and the Day-Ahead Ancillary Services Strike Price and (2) zero. As described above and in the Testimony of Matthew White, this formula represents the fact that the close-out charge is zero unless the Real-Time Hub Price exceeds the strike price. The net credits to sellers ultimately will be charged to load, as load receives the benefits of the procured Day-Ahead Ancillary Services.

For example, assume a resource that is a Generator Asset has an award of 100 MWh of DA TMNSR and 50 MWh of DA EIR. Assume further that the DA TMSNR clearing price is $3/MWh and the FER Price, which is the price paid to DA EIR, is $2/MWh. The Real-Time Hub Price in this case exceeds the strike price by $1/MWh, resulting in a $1/MWh close-out charge rate. In this case, the seller's credit for the award would be the sum of (1) 100 MWh multiplied by $3/MWh and (2) 50 MWh multiplied by $2/MWh, with the resulting credit of $400. During settlement, the seller also would be charged the close-out charge rate of $1/MWh multiplied by the total 150 MWh of the Day-Ahead Ancillary Services award, resulting in a close-out charge of $150. The net credits to the seller in this case would be $250 for its Day-Ahead Ancillary Services award.

Q: How will the ISO settle Day-Ahead energy awards that contribute to satisfying the FER Demand Quantity?

A: All Day-Ahead energy that is cleared on physical supply resources (*i.e.*, Generator Assets, DRRs, and Imports) contributes to satisfying the FER. Consequently, the ISO will settle such Day-Ahead energy award MWh quantities by crediting the seller with the Day-Ahead energy MWh quantity multiplied by the FER Price. Such credits are referred to as FER Credits.

Q: You mentioned above that DASI will require confirmation that imports cleared for Day-Ahead energy have submitted a corresponding Real-Time transaction in order for those transactions to receive FER payments. Please explain this requirement and why it is appropriate.

A: As noted, all physical Day-Ahead energy awards contribute to satisfying the FER Demand Quantity, and are therefore eligible to be paid the FER Price for those awards. Additionally, as discussed, the intent of the FER Demand Quantity is to procure sufficient Day-Ahead awards on resources to ensure that the load forecast can be satisfied in Real-Time, should those resources need to be called upon to do so.

The requirement that Day-Ahead cleared imports also submit a corresponding Real-Time transaction in order to receive the FER Price is intended to provide an appropriate incentive to ensure that, if the Day-Ahead cleared import must be scheduled in Real-Time to meet the load forecast, then that import can in fact be scheduled. Per current market rules, an import that clears in the Day-Ahead Energy Market must pro-actively take an additional step to also submit a corresponding transaction to the Real-Time market in order to then be scheduled in Real-Time.[19] If it does not take this step, then the transaction cannot be scheduled in Real-Time and is therefore not useful to satisfying the load forecast. By requiring that Day-Ahead cleared imports also submit corresponding Real-Time transactions to receive the FER Price, the design provides an incentive for such imports to ensure they take steps necessary to be able to be scheduled in Real-Time, and therefore be useful for satisfying the load forecast.

Similar rules are not needed for Generator Assets and DRRs. Per current market rules and operational practices, the Supply Offers of Generator Assets and Demand Reduction Offers of DRRs are automatically carried forward from the Day-Ahead market to the Real-Time market. As a result, there are no additional steps that must proactively be taken for Generator Assets or DRRs to ensure their resources can be scheduled in Real-Time if needed.

[19] See Tariff, Section III.1.10.7(a) of Market Rule 1.

Q: How will the costs associated with the credits paid to sellers for providing Day-Ahead Ancillary Services be allocated?

A: The design of the Day-Ahead Ancillary Services Market is region-wide, meaning that all Real-Time load within New England benefits from the reliable, next-day operating plan that this market provides and the strong incentives it creates for sellers of Day-Ahead Ancillary Services to prepare to operate if called upon in Real-Time.[20] Because Day-Ahead Ancillary Services are procured for the benefit of Real-Time load, the associated costs are generally charged to internal Real-Time Load Obligation on a pro-rata basis, with certain exceptions.

Q: How are credits to resources that provide Day-Ahead Flexible Response Services charged to load?

A: Day-Ahead Flexible Response Services credits are charged on a pro-rata basis to certain Real-Time Load Obligation on a beneficiary pays basis. This cost allocation approach is modeled on that currently in effect for Real-Time Operating Reserves, as these Day-Ahead and Real-Time products have the same purpose: to enable to the region to maintain reliability in the event of a large source-loss contingency.

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[20] The incentives created by the new market, in particular by the call-option settlement structure, are explained in the Testimony of Matthew White.

The Real-Time Load Obligation considered for Day-Ahead Flexible Response Services cost allocation includes all Real-Time Load Obligation incurred at nodes internal to the New England control area, except for Real-Time Load Obligation incurred by Storage DARDs. As with Real-Time Operating Reserves cost allocation, Storage DARDs are exempt from allocation of Day-Ahead Flexible Response Services costs because these contingency reserves are not procured for the benefit of the consumption of such price-sensitive demand. Indeed, it is expected that if a contingency were to occur in real-time, Storage DARDs should generally expect to be dispatched to stop consuming.

The Real-Time Load Obligation considered for Day-Ahead Flexible Response Services cost allocation excludes all Real-Time Load Obligation at External Nodes, with the exception of Real-Time Load Obligation associated with Capacity Export Through Import Constrained Zone ("CETICZ") Transactions and Forward Capacity Auction ("FCA") Cleared Export Transactions, which are included in Day-Ahead Flexible Response Services cost allocation. Generally, contingency reserves are not procured with the intent of continuing to support the flow of external transactions in the event of a contingency, and so Real-Time Load Obligation associated with exports from New England are not beneficiaries of Day-Ahead Flexible Response Services and therefore do not share in the allocation of these costs. The two types of exports noted above, CETICZ and FCA Cleared Exports, are exceptions to this rationale. These two types of export transactions are considered to be "supported in real-time." Namely, these transaction types are considered in the planning of resource commitment in order to be treated more comparably to “native” or “firm” load and enhance the likelihood that such transactions will flow as requested in Real-Time. As such, these two transaction types do benefit from Day-Ahead Flexible Response Services, and as a result share in the allocation of these costs.

Q: How are credits to those resources receiving the FER Price (*i.e.*, FER credits and DA EIR credits) charged to load?

A: The sum total of credits that go to resources for their contribution to satisfying the FER Demand Quantity, which includes both FER Credits and DA EIR Credits, are allocated to load in the following manner.

First, all Day-Ahead cleared export transactions are charged for their Day-Ahead cleared energy MWh quantity at the FER Price, on a cost causation basis. Each MWh of Day-Ahead cleared export directly results in an increase in FER costs at the FER Price, because an additional MWh of physical supply must be procured to satisfy each MWh of Day-Ahead cleared export.

Second, all remaining credits will be charged, on a pro-rata basis, to Real-Time Load Obligation incurred at nodes internal to New England, excluding that of Storage DARDs, on a beneficiary pays basis. The FER Demand Quantity is applied for the benefit of “firm” Real-Time load internal to New England, and it ensures sufficient capability is procured to satisfy that expected load, as represented by the ISO's next-day load forecast. Storage DARD consumption is not reflected in the load forecast, and the FER Demand Quantity is not applied for the benefit of Storage DARDs. Because Storage DARDs neither cause FER costs nor benefit from them, they do not share in the allocation of these costs.

Q: How will close-out charges collected from sellers of Day-Ahead Flexible Response Services be allocated?

A: The sum total close-out charges collected from sellers of Day-Ahead Flexible Response Services shall be allocated as credits to those same participants who bear the cost of those services. Specifically, Day-Ahead Flexible Response Services close-out charges will be allocated as credits, pro-rata, to all Real-Time Load Obligation incurred at nodes internal to New England, except that of Storage DARDs, and to Real-Time Load Obligation associated with CETICZ Transactions and FCA Cleared Export Transactions.

Q: How will close-out charges collected from sellers of DA EIR be allocated?

A: The sum total close-out charges from sellers of DA EIR shall be allocated as credits to those same participants who bear the cost of that service on a beneficiary pays basis. Specifically, DA EIR close-out charges shall be allocated as credits, pro-rata, to all Real-Time Load Obligation incurred at nodes internal to New England, except that of Storage DARDs.

VIII. <u>FORWARD RESERVE MARKET SUNSET</u>

Q: Please provide some background on the Forward Reserve Market and its role in procuring reserves.

A: The Forward Reserve Market ("FRM") provides a seasonal forward payment to participants with reserve capable resources. The FRM provides forward obligations for two products: TMNSR and TMOR, with requirements set based upon historically observed first and second contingencies. In exchange for taking on a Forward Reserve Obligation, participants must offer an associated energy quantity into the Day-Ahead and Real-Time Energy Markets at or above an ISO determined price, known as the Forward Reserve Threshold Price ("FRTP"). Such energy offers must be made only for hours that fall within the specified Forward Reserve Delivery Period, which is hour ending 0800 through hour ending 2300 for each weekday, excluding those weekdays that are defined as NERC holidays. By requiring FRM resources to offer energy above the FRTP in certain hours, the likelihood of such resources being dispatched for energy is decreased in those hours, and they are consequently more likely to provide reserves in Real-Time.

Q: How does the Day-Ahead Ancillary Services Market differ from today's FRM?

A: There are many important ways in which the Day-Ahead Ancillary Services Market differs from the FRM. First, the Day-Ahead Ancillary Services Market makes explicit consideration of the reliability need to satisfy the load forecast, which is not a consideration in the FRM. Second, the Day-Ahead Ancillary Services Market fully reflects all constraints and demand quantities associated with maintaining required levels of operating reserves via Day-Ahead Flexible Response Services Demand Quantities and products. The FRM only considers a subset of these operating reserve requirements. Third, the Day-Ahead Ancillary Services Market is applied in all hours and on all days, just as reliability standards are applicable in all hours of all days. The FRM is only applicable in certain hours and on certain days.

Additionally, the Day-Ahead Ancillary Services Market will provide an explicit, hourly signal to the resources upon which the ISO is relying for a secure next-day operating plan in the form of Day-Ahead awards for ancillary services, and it will ensure the costs associated with providing those specific services are compensated through market clearing prices. The FRM does not directly relate to a secure, next-day operating plan in the same way. Instead, it simply requires certain resources to offer energy in such a way as to make them more likely to be held offline and providing reserves. It does not reflect all reliability needs on an hourly basis, nor do its awards provide such a targeted signal of the ISO's reliance to resources. The Day-Ahead Ancillary Services Market will send clearer information about which resources are being relied upon for those reserves in each hour of the Operating Day, as well clearer forward price signals reflecting the value of those reserve products in those specific hours.

Finally, the FRM, by its very design, has potential to distort Real-Time energy offers by requiring certain resources to offer their energy at or above the FRTP. This in turn may result in higher-than-necessary energy prices in the event that such resources must be dispatched to provide energy. The Day-Ahead Ancillary Services Market, on the other hand, introduces no distortionary effects on energy supply offers. The Day-Ahead Ancillary Services Market fully considers resources' expressed willingness to provide both energy and ancillary services, as indicated through their offers, without dictating the price above which reserve providers are required to make their energy supply offers. By allowing sellers of Day-Ahead Ancillary Services to offer their energy at competitive prices, rather than requiring that it be offered above a predetermined threshold, the design allows those competitive energy offers to be properly incorporated in Real-Time pricing and dispatch calculations. Resources that participate in the Day-Ahead Ancillary Services Market can, and should, offer their energy at competitive levels.

Q: Why is the ISO proposing to sunset the FRM as part of DASI?

A: The ISO proposes to sunset the FRM at the same time as the implementation of the new Day-Ahead Ancillary Services Market because the FRM is incompatible with the new Day-Ahead Ancillary Services Market.

Q: How is the FRM incompatible with the new Day-Ahead Ancillary Services Market?

A: Despite the differences between the two markets, both provide a type of forward payment to participating resources for certain reserve capabilities required by the region. Maintaining two separate and distinct markets, each of which procures these capabilities, would result in at least two issues.

First is the issue of double compensation. Keeping the FRM in place with the Day-Ahead Ancillary Services Market risks, in some ways, double compensating resources being relied on by the ISO for reserves in Real-Time. Despite the differences between the two markets, both provide a type of forward payment to certain resources for certain required reserve capabilities. Maintaining two separate and distinct markets, each of which procures these capabilities, could result in compensating the same resource twice for providing a single service.

Second is the issue of divided participation between the two markets. If both markets co-existed, participants that cleared in both markets would be exposed to two sets of non-performance charges for the provision of a single capability. In the FRM, they would be exposed to the Forward Reserve Failure-to-Activate Penalty, Forward Reserve Failure-to-Reserve Penalty, and Forward Reserve Obligation Charge. In the Day-Ahead Ancillary Services Market, they would be exposed to the Day-Ahead Ancillary Services Market Close-Out Charge. If both markets were to co-exist, there would be potential for participants to choose to sell their reserve capability in one market or the other, but not both. This would reduce the pool of supply in each market and thereby reduce the competitiveness of each market, thereby resulting in uncompetitively high prices in each market. For example, if suppliers were to perceive that the FRM's non-performance penalties are less onerous overall, they may participate only in the FRM to the exclusion of participating in the Day-Ahead Ancillary Services Market. This would undermine the proposed market, which, as I have described, provides more targeted definition and compensation than the FRM with regard to the ISO's reserve needs in Real-Time, and the reduced supply may increase market power concerns in the new market.

Importantly, these issues cannot be resolved through modifications to the existing FRM. Instead, a complete redesign of the FRM would be required to ensure compatibility with the Day-Ahead Ancillary Services Market. Such a redesign is not within the scope of our current effort. In addition, any redesign would necessarily require further FRM design changes to address issues raised by the ISO's market monitors as well. The External Market Monitor has expressed concerns regarding the design of the FRM, including its potential distortionary effects on Real-Time energy offers and subsequently on Real-Time energy prices, and has recommended consideration of retiring the FRM.[21] Even if the ISO were inclined to retain the FRM, doing so would require an investigation into and, likely, the pursuit of rule changes to address the concerns raised by the ISO's

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[21] Potomac Economics, *2014 Assessment of the ISO New England Electricity Markets*, at 12–13 (June 2015), *available at* https://www.iso-ne.com/static-assets/documents /2015/06/isone_2014_emm_report_6_16_2015_final.pdf.

market monitor. The ISO does not currently see value in redesigning the FRM to address these issues and to conform to DASI when the Day-Ahead Ancillary Services Market will provide the incentives necessary to compensate resources for the reserves they provide in a way more precisely tied to the needs of the system.

Q: Is the ISO open to pursuing a new forward market for reserves in the future?

A: The ISO is open to investigating and considering a new forward market for reserves. Before doing so, it is important that the region has enough experience with the Day-Ahead Ancillary Services Market to draw conclusions about the need for such a forward market, and time to consider how to design such a market in a way that complements the Day-Ahead and Real-Time procurement of reserves. A key to the design of any forward market is a well-designed spot market, and the Day-Ahead Ancillary Services Market would be expected to serve as the spot market for any further-forward market for reserve capability that may be designed in the future. Further, the ISO would have to consider the value of a new forward market in light of other potentially more valuable reserve market designs, such as the addition of longer-duration reserves to the Day-Ahead and Real-Time markets.[22]

[22] The ISO has highlighted the potential value of longer-duration reserves in its report to the Commission in FERC Docket No. AD21-10 and in other forums.

IX. IMPACT ASSESSMENT

Q: What is the Impact Assessment that the ISO conducted for the proposed Day-Ahead Ancillary Services Market?

A: The Impact Assessment is a quantitative and qualitative assessment of the proposed Day-Ahead Ancillary Services Market's impact on market outcomes, including sellers' revenues from the market, the cost to consumers for the market, and changes to revenues and consumer costs in other ISO markets that will likely result from the proposed Day-Ahead Ancillary Services Market. The Impact Assessment is a set of simulated market results showing how Day-Ahead Market results would have been different from those observed under current market rules if the Day-Ahead Ancillary Services Market as proposed in this filing had been in place. The Impact Assessment results included not only simulated market results showing the impact to energy and ancillary services revenues but also impacts resulting from the elimination of the FRM and impacts that the new Day-Ahead Market will have on NCPC. As described further below, the Impact Assessment involved limited consideration of the impacts of DASI on capacity market revenues, given the complexities involved in analyzing such impacts.

Q: How did the ISO design the Impact Assessment to study these outcomes?

A: The ISO performed the Impact Assessment using a Day-Ahead Market simulation that includes the proposed Day-Ahead Ancillary Services products and related constraints. Using historical Day-Ahead Energy Market input data from 2019 through 2021, as well as simulated estimates of competitive ancillary services offers for that period, the ISO simulated the proposed Day-Ahead Market that will include Day-Ahead Ancillary Services both with the strike price set to the expected Real-Time Hub Price and the strike price set to $10/MWh above the expected Real-Time Hub Price (that is, with the base strike "adder").

Q: Please elaborate further on the historical input data that the ISO used to conduct the Impact Assessment.

A: The ISO used historical market data from 2019 through 2021 to conduct the Impact Assessment. The ISO determined those three years to be a useful study period because that period is recent enough to represent New England's current resource fleet and also demonstrates a wide variation in energy demand, input prices, and Day-Ahead LMPs.[23]

Table 2

Year	Avg DAM Load Forecast (MWh)	Avg DA Gas Price ($/MMBtu)	Avg DA LMP ($/MWh)
2019	13291	$ 3.18	$ 31.22
2020	12983	$ 2.00	$ 23.31
2021	13179	$ 4.53	$ 45.92
Average	13151	$ 3.24	$ 33.48

[23] To put these Day-Ahead LMP and gas price averages in context, the ISO collected data on Day-Ahead Hub LMP and day-ahead gas prices from February 2016 to present. Including 2022, which had extremely high gas prices, the average DA LMP and day-ahead gas price for this range is $41.92/MWh and $4.17/MMBtu. Excluding 2022, the average DA LMP and gas price for the date range is $34.55/MWh and $3.46/MMBtu. In other words, including 2022, the Impact Assessment study period includes one above average year (2021) and two below average years (2019 and 2020). Excluding 2022, the Impact Assessment study period includes one above average year (2021), one roughly average year (2019) and one below average year (2020).

The historical inputs from this time period included all historical Day-Ahead market hourly input data, which included energy offers and associated resource physical parameters included in those offers, such as startup and notification times, ramp rates, and minimum down and minimum run times. The historical hourly input data also included energy demand bids, external transactions, reserve requirements, and the next-day hourly load forecast. The simulation included modeling of internal transmission interfaces because they affect Day-Ahead energy awards and unit commitment, even though Day-Ahead Ancillary Services products are all system-level products.

Q: Please elaborate further on the simulation the ISO ran of the proposed Day-Ahead Market.

A: The Impact Assessment study of the proposed Day-Ahead Market uses a new state-of-the-art market simulation tool recently developed by the ISO. This tool is able to replicate the core mechanics of the existing Day-Ahead Energy Market, and can be adjusted to further examine the impacts of proposed rule changes, such as the introduction of the Day-Ahead Ancillary Services Market. This simulation tool is able to fully reflect key considerations of the ISO's production market clearing engine, such as a unit commitment logic, unit-level constraints (*e.g.*, ramp rates, operating limits, etc.), internal transmission interface limits, and clearing and pricing logic. It is important to acknowledge that, in its current form, this market simulator cannot reflect all complexities currently modeled in the ISO's production market clearing engine, including the complete system topology (inclusive of branch flow limits) and simultaneous feasibility test constraints. We expect such features to be added to the market simulator as its development continues, but they were not available at the time the DASI Impact Assessment was performed.

To create Day-Ahead Ancillary Services Offers that would serve as inputs into the simulation, the ISO used the resource-specific data it had to determine estimated competitive Day-Ahead Ancillary Services Offers in accordance with the competitive offer methodology described in the Testimony of Dr. Parviz Alivand. The ultimate outputs of the simulation were clearing prices, by product by hour, and cleared quantities, by resource by hour, for Day-Ahead energy and for the four Day-Ahead Ancillary Services products.

Because the market simulator cannot fully capture all the complexities inherent in the production market clearing engine, the ISO also had to use the market simulator to produce market outputs from 2019 through 2021 under current market rules. This was done to create a baseline from which to compare the impact of the simulation of the proposed Day-Ahead Market. The differences between the simulations of the new Day-Ahead Market and the simulated historical results (*i.e.*, those under current market rules) serve as the basis for the estimates of the changes in buyers' costs and sellers' revenues.

In its modeling of the new Day-Ahead Market, the ISO also reflected the expectation that the application of Day-Ahead Ancillary Services constraints will increase demand participation in the Day-Ahead Market, resulting in convergence of Day-Ahead LMPs with expected Real-Time LMPs, as explained in Section VI.B above. To reflect this expectation that load will increase its Day-Ahead energy purchases, the ISO added additional priced energy demand bids into the Impact Assessment's simulation of the proposed Day-Ahead Market. In this way, the Impact Assessment accounts for the expected market response from implementation of the Day-Ahead Ancillary Services Market, and is reflective of the conditions we expect to hold at market equilibrium.

Q: Did the ISO do anything to test the accuracy of its Day-Ahead Market simulation?

A: Yes. The ISO benchmarked the market simulator with current market rules applied against the production market clearing engine, which was run with only those considerations able to be reflected in the market simulator in effect. Further, the ISO performed extensive testing of the simulation platform with the Day-Ahead Ancillary Services Market applied, ensuring the proper enforcement of constraints and the accuracy of resulting clearing prices and cleared quantities.

Q: What were the ultimate outputs of the Impact Assessment?

A: As noted above, the Impact Assessment produced a comparison between the simulated market outputs of the proposed Day-Ahead Market and comparably simulated historical market outputs under current market rules. From this, the ISO was able to determine estimates of the changes to energy and ancillary services revenues experienced by suppliers (and, ultimately, costs to consumers) that will result from the implementation of this new Day-Ahead Market. The Impact Assessment also studied the impact of the proposed changes to the Day-Ahead Market on other markets and revenue sources, such as NCPC. Included with the assessment was also a consideration of the elimination of the FRM and its revenues.

Q: What did the results of the Impact Assessment show regarding energy and ancillary services revenues to resources and costs to consumers?

A: The results of the Impact Assessment showed, on average, an estimated increase in Day-Ahead and Real-Time energy and ancillary services revenues to providers and costs to consumers of $139.9 million per year, which is an average 1.4 percent increase in total annual wholesale market revenues and costs. As discussed below, the retirement of the FRM and by reductions in Day-Ahead NCPC credits further reduce the estimated increase to $104.4 million, or 1.1 percent of total wholesale market costs.

Below is a yearly breakdown for each of the three simulated years that is representative of the estimated increase in energy and ancillary services revenues:

Table 3

Year	Estimated E&AS Cost/Revenue Change due to DASI ($ millions)	Percent Change in Total Wholesale Market Costs
2019	$ 127.1	1.3%
2020	$ 104.4	1.3%
2021	$ 188.2	1.7%
Average	$ 139.9	1.4%

Below is the breakdown by type of Day-Ahead credit and charge of the average annual cost across the three simulated years:

Table 4

		DASI ($ million) [A]	Change from Current Market Rules ($ million) [B]
DA Charges/Credits			
[1]	DA LMP Charge/Credit	$ 4,462.4	$ 57.7
[2]	FRS Total	$ 88.6	$ 88.6
[3]	EIR	$ 1.7	$ 1.7
[4]	FER	$ 125.3	$ 125.3
[5]	Total DA Charges/Credits	$ 4,678.1	$ 273.3
Factors That Reduce Costs/Revenues			
[6]	Expected Decrease in RT LMP Charge/Credit	n/a	$ (64.6)
[7]	Expected DA A/S Closeout Charge/Credit	$ (68.8)	$ (68.8)
Average Estimated Total Change in Buyer E&AS Cost/Seller E&AS Revenue due to DASI			
[8]	Average Total Cost/Revenue Change	n/a	$ 139.9

The average annual estimated increase in total Day-Ahead costs, excluding any comparative savings from the shift of some Real-Time energy purchases to Day-Ahead and any charges to sellers and credits to load due to the close-out charge, is $273.3 million (B1 + B2 + B3 + B4 in Table 4 above). The largest source of this increase are the FER credits to sellers of energy, in an amount of $125.3 million. The average yearly credits to resources for the four Day-Ahead Ancillary Services products was a total of $90.3 million (B2 + B3 in Table 4 above), exclusive of any close-out charges. The average estimated yearly close-out charges, however, were $68.8 million, resulting in a net estimated cost to load (and revenues to suppliers) for the four Day-Ahead Ancillary Services products of only $21.5 million (B2 + B3 – B7 in Table 4 above). Together, these factors produce the estimated annual increase in Day-Ahead costs of $139.9 million (B5 – B6 – B7 in Table 4 above).

The net revenues for Day-Ahead Ancillary Services generally go to those fast, flexible resources that the ISO relies upon today to provide Real-Time Operating Reserve, and to quickly respond to satisfy Real-Time load. Notably, this set of resources includes storage resources, which are important providers of reserve capability. While the ISO's current storage fleet is comprised primarily of pumped storage hydro resources, it is expected that such revenues will also go to grid-connected batteries as they begin to penetrate the market.

Q: You explained earlier that the ISO expects increased Day-Ahead energy awards with the proposed Day-Ahead Market. What did the Impact Assessment show in terms of increased Day-Ahead energy awards?

A: When simulating the market response to the proposed Day-Ahead Market with Day-Ahead Ancillary Services and the impact of the FER Demand Quantity to meet load projections, the Impact Assessment showed a roughly estimated 2,000 GWh of Day-Ahead energy clearing per year compared to today's Day-Ahead energy market. That is approximately 1.7 percent more per year than today. This is a direct result of the application of the FER Demand Quantity, and the additional energy from physical supply resources that is procured to satisfy that demand quantity.

Q: Does this increase in cleared physical energy supply relate to the increased Day-Ahead LMP-related costs shown in Table 4 above?

A: Yes. The Impact Assessment's market response modeling showed an average yearly increase in Day-Ahead LMP-related costs of approximately $57.7 million, which, as stated above, takes into account the simulated market response whereby demand will increase its Day-Ahead bids. These increased Day-Ahead LMP-related costs stem directly from the increase in the cleared quantity of energy supply in the proposed Day-Ahead Market, as a result of the application of the FER constraint (which, as discussed in Section VI.B, will clear additional energy supply in hours with a Day-Ahead energy gap), and further as a result of the expected increase in bid-in energy demand that is expected as a result of the application of the FER constraint. Importantly, these costs are not increasing because Day-Ahead LMPs have materially increased as a result of proposed design.

Q: Is it a correct interpretation of Table 4 that there is an overall increase in annual Day-Ahead energy costs due to the average yearly $57.7 million increase in Day-Ahead LMP-related costs and the addition of FER payments?

A: Yes, because Day-Ahead energy awards will receive both the Day-Ahead LMP and FER payments, the cost of Day-Ahead energy is expected to increase compared to the cost under current market rules. In addition to the Day-Ahead LMP-related cost increase, the estimated average yearly FER payment cost shown in the Impact Assessment was approximately $125.3 million. Together with the estimated increase in Day-Ahead LMP-related costs, the total annual yearly Day-Ahead energy cost increase shown by the Impact Assessment is approximately $183 million. The increase is mitigated, however, by cost reductions that would result from the need to procure less incremental energy at Real-Time prices to satisfy load.

Q: Please explain how there will be less of a need to procure energy at Real-Time prices, and how this will mitigate some of the anticipated increase in Day-Ahead energy costs.

A: The Impact Assessment showed an average yearly cost reduction of approximately $64.6 million due to a change in incremental Real-Time energy procurement costs. Incremental Real-Time energy costs are simply the cost to load of procuring Real-Time energy to satisfy deviations between Real-Time load and the amount of energy procured in the Day-Ahead Energy Market. Namely, it is the cost to cover the additional energy needed to be purchased in Real-Time when actual load exceeds what cleared in the Day-Ahead.

Because the Impact Assessment, consistent with the ISO's expectations, showed an increase in cleared Day-Ahead energy under DASI, there is an expected cost savings associated with a corresponding decrease in Real-Time energy purchases to satisfy Real-Time load. This expectation relies on a number of assumptions. First, the ISO assumed that Real-Time energy demand is independent of the Day-Ahead Market structure (*i.e.*, DASI will not impact Real-Time energy demand). Because Real-Time loads are driven primarily by factors like temperature and humidity, which do not depend on the Day-Ahead Market structure, this is a reasonable assumption for the purpose of this analysis. Second, the ISO assumed that the Real-Time LMP is independent of the Day-Ahead Market structure as well. Although in theory DASI might impact Real-Time LMPs relative to current market rules, there is no way of estimating such an impact, and the ISO expected that, on average, any impacts should be small.

To estimate this cost savings, the ISO relied on the expected consumer cost of procuring additional energy in Real-Time under the current market rules simulation compared to the DASI simulation. Because the ISO assumed that Real-Time energy demand is independent of the Day-Ahead Market structure, the ISO calculated the difference between the amount of Day-Ahead energy cleared in the DASI simulation and the amount of Day-Ahead energy cleared in the current market rules simulation to determine how much more energy would need to be purchased in Real-Time under the current market rules simulation. As a proxy for the Real-Time LMP that would be paid to satisfy this deviation in both simulations, the ISO used the expected Real-Time Hub Price, derived from the Gaussian Mixture Model ("GMM") that the ISO will use to derive strike prices for the Day-Ahead Ancillary Services Market.[24] The ISO multiplied the expected Real-Time LMP by the MWh difference in cleared Day-Ahead energy between the simulations to determine the ultimate anticipated cost savings associated with avoided Real-Time energy purchases, which was $64.6 million per year.

Q: Why does it make sense that overall Day-Ahead energy costs should increase on average with the introduction of DASI compared to current market rules?

A: With the application of the Day-Ahead Ancillary Services Market, the ISO will be ensuring a secure next-day operating plan with sufficient physical supply capability to satisfy the load forecast through market means. Importantly, this means that the costs of satisfying this key reliability requirement will, for the first time, be reflected through the market, and the supply capability the ISO relies upon to satisfy it will, for the first time, be fully compensated for its contribution to satisfying that requirement.

[24] The GMM is described at length in Dr. Parviz Alivand's testimony.

At root, this finding reflects the motivating concerns detailed in the Testimony of Dr. Matthew White. Generally, if the key reliability services we rely upon go uncompensated, they may not continue to be made available. And under current market rules, contributions to satisfying the load forecast and thereby supporting a reliable Day-Ahead operating plan currently go uncompensated when the load forecast exceeds cleared Day-Ahead physical energy.[25]

It is important to also note the targeted nature of these increased costs resulting from the application of the FER Demand Quantity. As discussed above, the FER constraint will impact market clearing and pricing only in hours when a Day-Ahead energy gap exists, and in those hours it will procure a mix of additional physical energy supply and EIR to ensure the load forecast is satisfied. As noted above, such a Day-Ahead energy gap exists in only approximately 50 percent of the hours in our historical period. In hours when no Day-Ahead energy gap exists, no additional costs related to satisfying the load forecast are incurred.

Q: Can the FER Price be $0/MWh in hours that presently have a Day-Ahead Energy Gap?

A: Yes. As noted above, we observe a Day-Ahead energy gap in 50 percent of hours historically from 2019 through 2021 under current market rules. The Impact Assessment's simulation with DASI rules in effect found, however, that the FER

[25] The issue of under-compensation is discussed at length in the Testimony of Matthew White.

Price is non-zero in 31 percent of hours during this period. Therefore, for 19 percent of hours that had a Day-Ahead energy gap under current market rules, the Impact Assessment showed a FER Price equal to $0/MWh, despite the gap.

There are three reasons that such a result may occur. The first reason relates to increased demand-side participation in the Day-Ahead Market that is expected to result from the application of the FER Demand Quantity, and that the ISO simulated with increased demand bids. With increased demand participation, the likelihood that the Day-Ahead Market clears physical energy supply that meets or exceeds the load forecast increases. This can result in the Day-Ahead energy gap being resolved with the FER Price being $0/MWh.

The second reason is due to the “lumpiness” associated with the minimum operating limit of supply resources. When seeking to procure sufficient physical energy supply capability to satisfy the FER, the market clearing engine may find it most efficient to commit a resource with an Economic Minimum that slightly exceeds the magnitude of the Day-Ahead energy gap. This can result in a clearing outcome that has more aggregate physical energy supply capability than the load forecast, and therefore, based on standard marginal cost pricing logic, a FER Price of $0/MWh.

The third reason relates to Storage DARDs being committed to consume energy in order to also access their capability to provide Flexible Response

Services. When such a DARD commitment is made, additional energy supply must also be cleared to ensure that bid-in energy demand is equal to offered energy supply. This additional physical supply, in turn, may cause the aggregate physical energy supply cleared in the Day-Ahead Market to exceed the load forecast. Again, based on standard marginal cost pricing logic, the FER Price will be $0/MWh in such a case.

Q: According to the Impact Assessment, what are representative Day-Ahead Prices in the proposed Day-Ahead Market?

A: Below is a chart showing average prices for each of the Day-Ahead Prices studied by the Impact Assessment, as well as 25th, 75th, 90th, 95th, and 99th percentile values illustrating the range of prices and prices at the higher extremes. For background, Day-Ahead LMPs in the DASI simulation were only, on average $0.01/MWh or 0.58 percent higher than the DA LMPs observed in the current market rules simulation.

<u>Table 5</u>

Clearing Price	Mean	25th Percentile	75th Percentile	90th Percentile	95th Percentile	99th Percentile
DA Hub LMP	$ 34.32	$ 20.73	$ 40.90	$ 61.19	$ 77.40	$ 112.07
FERP	$ 0.95	$ -	$ 0.98	$ 3.02	$ 5.30	$ 10.70
DA TMSR RCP	$ 6.14	$ 2.44	$ 7.94	$ 12.24	$ 16.48	$ 29.80
DA TMNSR RCP	$ 3.58	$ 1.55	$ 4.29	$ 7.53	$ 10.13	$ 15.88
DA TMOR RCP	$ 3.56	$ 1.52	$ 4.26	$ 7.51	$ 10.08	$ 15.88

As mentioned above, the FER Price is zero in 69 percent of hours studied, resulting in a low mean value of $0.95/MWh. Not shown in the table above, the average FER Price across hours when that price is non-zero is $3.49/MWh. At its most extreme, the FER Price in the 99th percentile of prices is $10.70/MWh. Because the DA EIR receives the FER Price, this price also represents the price of that ancillary service.

For the Day-Ahead Flexible Response Services, DA TMSR present the highest prices, with an average price of $6.14/MWh, and a 99th percentile price of $29.80, reflecting the 'cascading up' of the Flexible Response Services constraint shadow prices discussed in Section VI.B above. The prices of DA TMNSR and DA TMOR are substantially similar, with both mean and percentile prices within $0.05/MWh of each other. The average prices of DA TMNSR and DA TMOR were $3.58/MWh and $3.56/MWh, respectively. The 99th percentile price for both is $15.88/MWh.

Q: What are representative cleared quantities of the four Day-Ahead Ancillary Services products?

A: Below is a chart showing representative cleared quantities for the four Day-Ahead Ancillary Services products from the Impact Assessment:

<u>Table 6</u>

Summary statistics for cleared quantities of each Day-Ahead Ancillary Service product, 2019 - 2021 (MWh)

Product	Mean	25th Percentile	75th Percentile	90th Percentile	95th Percentile	99th Percentile
EIR	49	0	0	179	328	686
TMSR	634	585	631	754	897	1134
TMNSR	1298	1116	1526	1654	1711	1801
TMOR	463	269	667	784	804	839

The annual average of hourly cleared quantities of DA TMSR, DA TMNSR, and DA TMOR are 634 MWh, 1298 MWh, and 463 MWh, respectively. The annual average of the hourly cleared quantity of DA EIR is 49 MWh, which is less than the 181 MWh average energy gap observed for the years 2019 through 2021.

Q: How do the total costs of implementing the Day-Ahead Ancillary Services Market compare to a design that does not include the $10/MWh base strike adder?

A: As discussed in the testimonies of Dr. Matthew White and Dr. Parviz Alivand, the strike price includes the base strike price as well as a base strike adder of $10/MWh. Given stakeholders' expressed interest in the impact of the base strike adder on consumer costs, the Impact Assessment considered the costs of the proposed Day-Ahead Ancillary Services Market both with and without the $10/MWh base strike adder that is included as part of the design submitted as part of this filing. As noted above, the total energy and ancillary services costs resulting from the proposed market including the base strike adder are an average annual $139.9 million. The average annual cost resulting from a Day-Ahead Market that includes the proposed Day-Ahead Ancillary Services Market without the adder (that is, where the strike price is simply set to the expected Real-Time Hub Price) would be $159.4 million. Consequently, the base strike adder results in a cost reduction and reduction in revenues to suppliers in the Day-Ahead Market of $19.5 million, which is an average 12 percent reduction annually.

Below is a chart showing the comparison between the market with and without the strike price adder for each of the three study years:

Table 7

	$10 Strike Price Adder ($ million) [A]		Base Strike Price ($ million) [B]		Cost Reduction from Strike Price Adder ($ million) [C]		Percent Reduction from Strike Price Adder [D]
Calculation					[B] - [A]		([B] - [A])/[B]
2019	$	127.1	$	141.9	$	14.7	10%
2020	$	104.4	$	117.7	$	13.2	11%
2021	$	188.2	$	218.7	$	30.5	14%
Annual Averages	$	139.9	$	159.4	$	19.5	12%

Q: What did the Impact Assessment show with regard to the elimination of the FRM and its impact on consumer costs?

A: As part of the Impact Assessment, the ISO looked at the total FRM credits and penalties assessed to FRM suppliers. Below is a chart showing the actual credits and charges across the three historical study years:

Table 8

E&AS Cost/Revenue Reduction due to FRM Sunset, 2019 - 2021 ($ million)						
	Total FRM Credits [1]		Total FRM Penalties [2]		Net FRM Credits [3]	
Calculation					[1] + [2]	
2019	$	39.4	$	(2.0)	$	37.4
2020	$	23.5	$	(0.6)	$	22.9
2021	$	19.9	$	(1.0)	$	18.9
Average	$	27.6	$	(1.2)	$	26.4

The average yearly net cost of the FRM across the three years, reflective of both credits and penalties, was $26.4 million. Consequently, the Impact Assessment's estimated energy and ancillary services annual cost of $139.9 million per year can be reduced further by $26.4 million.

It is important to note, however, that recent Forward Reserve Auctions have cleared at much higher prices, resulting in higher FRM credits to suppliers, and consequently net costs to load, than observed during the 2019 through 2021 study period. The net cost of the FRM for 2022 was $63.1 million, and a current projected cost of the FRM for 2023, taking into account the winter 2023/2024 FRM results, is $105.9 million. Consequently, the estimated net cost impact of applying the Day-Ahead Ancillary Services Market may be more significantly reduced as a result of the sunset of the FRM, if these more recent Forward Reserve Auctions are indicative of what FRM costs would be in future years.

Q: What did the Impact Assessment show with regard to the impact of the proposed Day-Ahead Market on Day-Ahead NCPC costs?

A: For background, Day-Ahead NCPC payments provide compensation to resources that are cleared in the Day-Ahead Energy Market and whose offered energy costs, including start-up, no-load, and incremental energy costs, are not covered by the Day-Ahead energy credits they receive. Such payments ensure that resources are not worse off as a result of following the ISO's commitment and dispatch instructions in the Day-Ahead Energy Market in the event that offered costs exceed revenues.

With the application of the Day-Ahead Ancillary Services Market, there will be a new set of offered costs, and a new set of revenues, in the Day-Ahead Market. As part of the Impact Assessment, the ISO used historical Day-Ahead NCPC credits during the study period and decreased those credits for resources by the Impact Assessment's estimated net Day-Ahead Ancillary Services and additional FER payments to those resources to estimate what the resource's NCPC credits would have been had the proposed Day-Ahead Market been in effect during that period. In this way, the ISO accounts for the additional Day-Ahead Ancillary Services offered costs and additional Day-Ahead Market revenues to estimate the impact on Day-Ahead NCPC costs. It is important to note, however, that the ISO has not yet performed a complete assessment of what Day-Ahead NCPC rule changes may be required or appropriate as a result of the application of the Day-Ahead Ancillary Services Market. Such an assessment will be forthcoming, and may or may not reflect the precise methodology employed in this Impact Assessment.

Below is a table showing the estimated reduction in Day-Ahead NCPC payments across all three years:

Table 9

	Estimated DA NCPC Credit	Historical DA NCPC Credit	Change in DA NCPC Credits due to DASI
2019	$ 3.2	$ 12.6	$ (9.4)
2020	$ 2.6	$ 9.6	$ (7.0)
2021	$ 3.7	$ 14.6	$ (10.8)
Average	$ 3.2	$ 12.3	$ (9.1)

Over the study period, the Impact Assessment estimated an average annual reduction in Day-Ahead NCPC payments of approximately $9 million, which was a 74 percent reduction in total Day-Ahead NCPC payments. Consequently, the Impact Assessment's estimated energy and ancillary services annual cost of $139.9 million per year can be reduced further by $9 million to account for the estimated reduction in NCPC costs.

Q: Taking into account the cost reductions resulting from elimination of the FRM and the impact on NCPC payments, what is the ultimate change in energy and ancillary services payments as a result of the proposed market changes?

A: Taking into account the FRM and NCPC payments, the Impact Assessment estimates a net total average annual increase in consumer costs of $104.4 million as a result of the proposed changes to the Day-Ahead Market to incorporate Day-Ahead Ancillary Services. The percentage change in wholesale costs is an estimated average annual increase of 1.1 percent. Below is a table showing the estimated increases in energy and ancillary services costs, net of the savings from elimination of the FRM and impact on NCPC payments, across all three study years:

Table 10

	Change in E&AS Costs due to DASI [1]	Change in E&AS Costs due to FRM Sunset [2]	Change in E&AS Costs due to Changes in DA NCPC [3]	Total Estimated Change in E&AS Costs due to DASI [4]	Historical Total Wholesale Market Costs [5]	Percent Change in Total Wholesale Market Costs [5]
Calculation				[1] + [2] + [3]		[4]/[5]
2019	$ 127.1	$ (37.4)	$ (9.4)	$ 80.3	$ 9,800.0	0.8%
2020	$ 104.4	$ (22.9)	$ (7.0)	$ 74.5	$ 8,100.0	0.9%
2021	$ 188.2	$ (18.9)	$ (10.8)	$ 158.5	$ 11,200.0	1.4%
Average	$ 139.9	$ (26.4)	$ (9.1)	$ 104.4	$ 9,700.0	1.1%

Q: What did the Impact Assessment show with regard to the impact of the proposed Day-Ahead Market on Forward Capacity Market costs?

A: The Impact Assessment did not include any quantitative estimates of the impacts of DASI on Forward Capacity Market costs for a number of reasons. First, different resources are impacted by the change in revenue streams with DASI differently. Depending on a resource's place in the supply stack, it will see increased revenues from FER revenues associated with their Day-Ahead energy awards, from Day-Ahead Ancillary Services awards, or from both, and potentially decreased revenues from the elimination of the FRM. To try to attempt some estimation of how this varied impact on different resources' revenue streams will impact the Forward Capacity Market would require a number of assumptions about potential retirements, a shifting supply stack, and adjustments on Net CONE that are too speculative for the purposes of a reliable assessment. Second, the current Resource Capacity Accreditation project, which has the potential to significantly impact how resources are compensated through the Forward Capacity Market, and regional inquiry into a prompt capacity market may make any attempt to understand DASI's impact on capacity payments under current Forward Capacity Market rules of limited utility.

Ultimately, because the Forward Capacity Market is designed to address the "missing money" problem for resources, the ISO would anticipate that, in the long run and all else being equal, capacity market payments will decrease because the new Day-Ahead Market will increase energy and ancillary services revenues for resources.

X. <u>CONCLUSION</u>

Q: Does this conclude your testimony?

A: Yes.

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

Executed on October 30, 2023.

Benjamin Ewing, Principal Analyst, ISO New England, Market Development

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

ISO New England Inc. and	)	**Docket No. ER24-_____-000**
NEPOOL Participants Committee	)	

TESTIMONY OF DR. PARVIZ ALIVAND
ON BEHALF OF
ISO NEW ENGLAND INC.

I. WITNESS IDENTIFICATION

Q: Please state your name, position, and business address.

A: My name is Parviz Alivand. I am a Manager, Market Design and Principal Economist in the Market Development department at ISO New England Inc. (the "ISO"). My business address is One Sullivan Road, Holyoke, MA 01040.

Q: Please describe your professional experience and qualifications.

A: I have held positions of increasing responsibility at ISO New England since January 2011. From January 2011 to October 2013, I served as a Senior Analyst, followed by a brief role as an Economist within the ISO's Internal Market Monitor from October 2013 to January 2014. Subsequently, from January 2014 to March 2020, I held the position of Economist in the ISO's Market Development department, with a promotion to Senior Economist from March 2020 to December 2020. I assumed the role of Principal Economist in December 2020 until October 15, 2023, within the same department. Starting October 15, 2023, I was appointed as the Manager of Market Design and Principal Economist in the Market

Development department at ISO New England.

I have worked extensively on various markets at ISO New England. During my time in the Internal Market Monitor ("IMM"), I was involved in developing measures to assess market power, evaluating the ISO's proposed designs for potential exercise of market power, and creating market power mitigation designs. Notably, I served as a core member of the team that designed the ISO's Pay-for-Performance enhancement within the Forward Capacity Market design, where I submitted testimony in support of mitigation design changes.

In the Market Development department, I contributed to a range of initiatives on energy, ancillary services, and capacity markets. For instance, I was a core team member for projects such as Competitive Auctions with Sponsored Policy Resources (CASPR), Zonal Demand Curves in the Forward Capacity Market, Fast-Start Pricing, Energy Security Improvements, and Opportunity Costs in Energy Market Offers, among others. My involvement extended beyond design, as I also closely oversaw the implementation of most of these projects, collaborating extensively with other ISO departments to ensure they were implemented according to the intended designs.

In my current role, I am primarily responsible for the design and development of the ISO's suite of auction-based electricity markets. I also oversee a team of highly skilled economists, engineers, and analysts who are dedicated to the design, development, and continued refinement and improvement of these markets.

I was one of the core team members in the design of the Energy Security Improvements ("ESI") project, and subsequent Day-Ahead Ancillary Services Initiative ("DASI"). I led the development of the design of the market power mitigation for DASI. This role involved organizing and overseeing a team of analysts and economists. Together, we developed mathematical and computer models that the ISO employed for market power assessment.

Prior to joining the ISO in 2011, I served as a visiting assistant professor at the University of Wisconsin. I hold a PhD in Economics from the University of Texas at Austin, with a research focus on Industrial Organization, specifically the theory and empirical study of firm entry and exit, contracts, regulation, and auctions. During my time at this institution and subsequently, I have also served as a referee for various economics and energy market journals.

I have earned a Master's degree in Business Administration and a Bachelor's degree in Civil Engineering from Sharif University of Technology in Tehran, Iran.

II. PURPOSE AND ORGANIZATION OF TESTIMONY

Q: What is the purpose of your testimony in this proceeding?

A: The purpose of my testimony is to explain the ISO's model and design for determining strike prices for the proposed Day-Ahead Ancillary Services Market, offer formation for the proposed market, and the proposed market-power mitigation measures to be applied in the Day-Ahead Ancillary Services Market.[1] The mitigation measures were developed following a market power assessment ("MPA") of the new Day-Ahead Ancillary Services Market; I also explain that assessment and the conclusions drawn from it to support the proposed mitigation measures.

Q: How is your testimony organized?

A: Section III discusses how the ISO will set the Day-Ahead Ancillary Services Strike Price. Section IV discusses the competitive offer formulation of the new Day-Ahead Ancillary Services products. Section V discusses and presents the results of the market power assessments the ISO performed to both evaluate the withholding incentives with the new Day-Ahead Ancillary Services products and inform the mitigation design. In Section VI.A, I discuss the rationale for the

[1] Capitalized terms used in this testimony but not otherwise defined herein shall have the meaning set forth in the ISO New England Transmission, Markets and Services Tariff (the "Tariff"), the Second Restated NEPOOL Agreement, the Participants Agreement, and in the proposed Tariff revisions submitted as part of this filing.

conduct and impact test framework the ISO selected for the mitigation design. In Section VI.B, I discuss and explain the conduct test and its component. Section VI.C explains the impact test design and mechanics of the ISO's proposed impact test. In Section VI.D, I present and discuss the consequences of failing the conduct and impact tests and application of mitigation. In Section VI.E, I discuss the consultation process and the fuel price adjustments available to resources participating in the Day-Ahead Ancillary Services Market. Section VI.F explains the cost recovery mechanism available under certain conditions when resources' Day-Ahead Ancillary Services offers are mitigated. Finally, Section VII explains the ISO's proposed physical withholding mitigation in the Day-Ahead Ancillary Services Market.

III. STRIKE PRICE CALCULATION

A. STRIKE PRICE MODELING

Q: How will the ISO calculate the Day-Ahead Ancillary Services Strike Price used for settling Day-Ahead Ancillary Services awards?

A: The ISO will calculate the Day-Ahead Ancillary Services Strike Price (referred to as "strike price") by adding $10 per MWh ("base strike adder") to the expected hourly Real-Time Hub Price ("base strike price") for the hour of the Operating Day associated with the Day-Ahead Ancillary Services offer, provided however that the strike price will never be less than zero. As explained in the Testimony of Dr. Matthew White, for the call-option incentive structure to achieve its goals, the strike price should be set based, in significant part, on the expected Real-Time energy price, which is approximately the region-wide average LMP for the hour for which the strike price is calculated. Consequently, the ISO has developed a statistical forecasting model to estimate, among other things, the expected Real-Time Hub Price (which is the base for the strike price) and will rely on this model when determining the strike price.

Q: Please describe the statistical forecasting model that will be used to predict Real-Time Hub Prices.

A: The ISO is planning to use a commonly used statistical model, known as the Gaussian Mixture Model ("GMM") to estimate the distribution of Real-Time Hub Prices (also referred to herein as "Real-Time Hub Prices"). A GMM is a sophisticated statistical model useful for forecasting asymmetric probability distributions and the attributes of those distributions. The GMM developed by the ISO for DASI generates a distribution of Real-Time Hub Prices for each hour of the Operating Day, depending on the variables that the statistical model determines are most impactful (*i.e.,* statistically significant) on the distribution of Real-Time Hub Prices.

For example, since natural gas is the most frequent marginal fuel in Real-Time, the ISO expects that the GMM will often find the price of natural gas be a key determinant of the shape of the distribution of the Real-Time Hub Prices. Another example is Real-Time load. A higher load typically translates into higher and more widely dispersed Real-Time LMPs. Thus, the load forecast, which is the ISO's best estimate of the Real-Time load, will play a key role in the shape of the distribution as well.

Q: Why did the ISO choose to use the GMM method?

A: One standard approach to statistically modeling price data is to approximate the data's distribution using a single familiar probability distribution, such as the bell-shaped normal distribution. A normal distribution, which shows a probability distribution symmetric about the mean, is also referred to as a Gaussian distribution. For electricity price data, however, a normal distribution is often a poor fit for observed Real-Time LMPs. The Gaussian Mixture Model approximates data using dynamic combinations of multiple normal distributions, to better match the frequency of each possible Real-Time LMP. The GMM accomplishes this by using historical data, identifying the best mean and variance for each distribution, and assigning the optimal weight that each distribution should have for each hour of data. This process results in the optimal mix of different normal distributions.

Q: Please elaborate further on why the GMM is a better fit for estimating Real-Time LMPs than other statistical models.

The ISO's GMM attempts to estimate the distribution of the Real-Time Hub Prices for each hour of Operating Day. The main reason for this is that common "point estimate" methods (*e.g.* linear regression models) do not explicitly account for the uncertainty in the Real-Time Hub Price—which is unknowable in the Day-

Ahead timeframe—and its non-normal distribution. For example, linear regression models make several important assumptions, including the assumption that the dependent variable is normally distributed around its expected value and that the dependent variable will have the same normal distribution irrespective of the values of the predictor variables. These assumptions are incorrect for the Real-Time Hub Price and its predictor variables. The GMM, however, explicitly accounts for the Real-Time Hub Price's non-normal distribution. This is why the GMM was found to provide a better estimate of the expected Real-Time Hub Price compared to other models the ISO developed and tested for this purpose.

The GMM has other advantages over point-estimate models. It is more robust in the presence of noise and outliers and does not rely on a single point estimate that can be easily influenced by extreme values. Instead, it accounts for uncertainty by providing probability distributions for each cluster or component, making it more resilient to noisy data. This is a desirable property because it allows the estimation to dissect potential Real-Time prices in a useful way. Most of the time, system conditions are close to what was anticipated in the Day-Ahead timeframe and the Real-Time prices are from a single cluster. But occasionally, Real-Time system conditions diverge from those expected in the Day-Ahead timeframe, and Real-Time prices are in different clusters than the first cluster.

Finally, the GMM can change the way it estimates the distribution of values in response to new data patterns that emerge from the model's inputs. In the case of the ISO's GMM for expected distributions of Real-Time Hub Prices, the GMM uses historical observations of both the independent variables (historical observation of natural gas prices, the load forecast, etc., as described in this testimony) and the dependent variable (historical observations of Real-Time Hub Price) to determine the distribution of the Real-Time Hub Price in the target hour. The process of using historical data to inform the distribution of Real-Time Hub Price for the target hour is referred to as "training the model."

Q: Will the ISO employ the GMM for other purposes than estimating the expected Real-Time Hub Price?

A: Yes. In addition, the estimated probability distribution of Real-Time Hub Prices for each hour of the next operating day enables the ISO to calculate the expected value of a Day-Ahead Ancillary Services seller's close-out charges (also called close-out costs), which are an important component of its net settlement under the call-option settlement design. That close-out charge settlement component is explained in detail in Section V of the Testimony of Dr. Matthew White. Furthermore, Section IV of my testimony provides additional discussion of close-out charges, including a numerical illustration of their calculation. This illustration also shows how to calculate the expected value of close-out charges, referred to as the Expected Close-Out Component, which is used for market power mitigation purposes.

Q: What data does the GMM rely on when estimating distributions of Real-Time Hub Prices for use in the Day-Ahead Ancillary Services Market?

A: The GMM will utilize data that are observable before the close of the Day-Ahead Ancillary Services Offer window. This dataset encompasses Day-Ahead load forecasts, 24-hour lagged LMPs (*i.e.* last available observed Real-Time Hub Price for a given hour), natural gas prices, No. 6 fuel oil prices, and several standard weather forecast measures. During the model testing phase, the ISO did not discover any significant improvements in the forecast model with the inclusion of additional variables. All the inputs originate from publicly available data sources provided by commercial vendors.

Following implementation of the proposed Day-Ahead Ancillary Services Market, the ISO will monitor the performance of the GMM and evaluate its accuracy. The ISO may make updates to the data used for training the model if it finds over time that doing so would improve forecast accuracy.

Q: What are the considerations when choosing historical data to inform the distribution of Real-Time Hub Prices for an Operating Day?

A: At a high level, there are two key considerations in determining which historical data elements should be used in the ISO's GMM: relevance and efficiency.

The ISO aims to incorporate data that are relevant to the distribution, considering both the nature of the data and its duration. The data used in the GMM process should directly pertain to the Real-Time Hub Price and its distribution. That is, the data generally should have reasonable high positive or negative correlation with the Real-Time Hub Prices. Therefore, as explained above, the ISO will utilize data such as natural gas prices and load forecasts to train the GMM.

Computational efficiency is also a factor. Namely, expanding the dataset to include data of only marginal relevance may add significant complexity without providing much benefit. For example, the quantity of the data, specifically the number of observations used in model training, is a crucial factor. Furthermore, historical observations from too far in the past may not offer particularly informative insights into the current state of the electric grid and resource mix. Expanding the set of data considered by the GMM to include such observations not only potentially impacts computational efficiency but also assigns weight to data points that may be irrelevant to today's pricing mechanisms and the composition of the current system.

Q: How did the ISO determine that its GMM was a reliable means of calculating Real-Time Hub Prices for the purpose of determining a strike price?

A: The ISO trained and tested a number of models, including different GMMs, using historical hourly LMPs and other observable data from 2012 through 2021. The training data for the models included the 61,289 hours from January 2012 through December 2018. Using this training data, the models' outputs were then tested against 26,304 hours of historical Real-Time Hub Prices from January 2019 through December 2021. The testing was conducted by using the model to forecast next-day hourly Real-Time Hub Prices for each day. Through this training and testing, the ISO determined that a GMM that mixes three normal distributions provided the best fit for predicting Real-Time Hub Prices and the full probability distribution of possible Real-Time Hub Price outcomes.

Q: What model outcomes did the ISO test in order to determine that its three-distribution (or "three-component") GMM was the best fit?

A: In testing the three-component GMM, the ISO calculated the model's errors (*i.e.* the expected Real-Time Hub Price predicted by the model net of the observed Real-Time Hub Price), and compared the GMM's performance to that of a leading commercial vendor's Real-Time Hub Price forecasts. The ISO also compared the GMM's expected Real-Time Hub Price to the Day-Ahead LMP, which, although determined when the Day-Ahead Energy Market clears and is unavailable for use in calculating the strike price prior to the Day-Ahead Energy Market, provides another reference for both the GMM and the leading commercial alternative.

The ISO found that the GMM's expected Real-Time Hub Price is strongly correlated with the observed Real-Time Hub Price, and that the forecasting errors were slightly smaller than the leading commercial alternative's forecasting errors. The table below shows the comparative correlation coefficients and error values for both the GMM and the leading commercial alternative.

Table 1

Forecast	Correlation Coefficient	Mean Absolute Error	Root Mean Square Error
ISO's GMM Real-Time price forecast	0.75	$9.27 per MWh	$15.77 per MWh
Commercial vendor Real-Time price forecast	0.71	$9.74 per MWh	$16.65 per MWh
For Reference Purposes:			
DA Hub LMP	0.83	$7.48 per MWh	$13.26 per MWh

In addition to having slightly larger forecasting errors, the leading commercial alternative does not provide a probability distribution of possible Real-Time Hub Prices, making it unable to estimate the Expected Close-Out Component of the conduct-test threshold used as part of the proposed market-power mitigation design discussed below in Section VI.B.1 The same is true for Day-Ahead LMPs, which, in addition to being calculated after the close of the jointly run Day-Ahead Energy Market and Day-Ahead Ancillary Services Market, also provide a single Day-Ahead Hub LMP and not a probability distribution that could be used to estimate the Expected Close-Out Component. Consequently, the GMM is both slightly more accurate than the leading commercial alternative and more fully meets the needs of the Day-Ahead Ancillary Services Market than both the leading commercial alternative and the Day-Ahead Hub Price.

The ISO also looked at how the forecasting errors of the GMM, the leading commercial vendor model, and the Day-Ahead LMP are correlated. In doing so, the ISO found that the GMM's forecasting errors were qualitatively similar to those of the leading commercial vendor's model and to Day-Ahead LMPs. Generally, for any given hour, if the GMM's error was an overestimation of the Real-Time Hub Price, then the leading commercial vendor's model and the Day-Ahead LMP also showed an overestimation and vice versa. In the comparison, the ISO also found no evidence that GMM will materially err in forecasting the Real-Time Hub Price when the other two models would not.

Q: Did the ISO perform any other evaluations of the GMM's accuracy in predicting Real-Time Hub Prices?

A: Yes. Additionally, the ISO evaluated the performance of the model in predicting the distribution of the Real-Time Hub Price by studying the GMM's *coverage probability*: the relative frequency with which the actual Real-Time Hub Price falls within the associated hours' day-before calculated statistical confidence intervals. The ISO found that the trained GMM performs well in estimating next-day confidence intervals for each hour's Real-Time Hub Price.

When a model is correctly specified and estimated, we expect the coverage probability to coincide with the significance level of the confidence interval (*e.g.,* we expect the 90 percent confidence interval to contain the realized Real-Time Hub Price 90 percent of the time, the 80 percent confidence interval to contain the realized Real-Time Hub Price 80 percent of the time, and so on). If the coverage probabilities are significantly different from the significance level of the model's confidence intervals, we can interpret it as evidence that the model's estimated probability distribution of Real-Time Hub Prices does not accurately reflect the likelihood and uncertainty associated with the actual RT LMPs (*i.e.*, the model predicts a narrower distribution than is actually observed, or vice versa), or that the model is not correctly specified.

The ISO performed this study with middle 50 percent, middle 80 percent, and middle 90 percent confidence intervals. The results are in the table below:

Table 2

Year	**50 percent Confidence Interval**	**80 percent Confidence Interval**	**90 percent Confidence Interval**
2019	51 percent	84 percent	94 percent
2020	53 percent	86 percent	94 percent
2021	46 percent	78 percent	89 percent
2019-2021	**50 percent**	**83 percent**	**92 percent**

As the results in the table show, on average across the three years of data used to train the GMM, the GMM produced reliable coverage probabilities. Observed historical Real-Time Hub Prices fell within the 50 percent confidence interval, on average, 50 percent of the time; within the 80 percent confidence interval, on average, 83 percent of the time; and within the 90 percent confidence interval, on average, 92 percent of the time.

Q: Did the ISO perform any evaluations of the GMM's accuracy in estimating expected close-outs?

A: Yes, the ISO tested the GMM's accuracy when used for estimating expected close-out costs in the Day-Ahead timeframe. Because no Day-Ahead Ancillary Services Market yet exists, the ISO used the GMM's forecasted expected Real-Time Hub Price to then calculate the hypothetical "realized" close-out cost for each hour of the testing period. The "realized" close-out cost was derived as the greater of (1) zero and (2) the difference between the actual Real-Time Hub Price minus the strike price (which is calculated as the sum of the GMM-generated expected Real-Time Hub Price and $10 per MWh base strike adder). This "realized" close-out was then compared to the GMM's expected close-out. The average estimate of the "realized" close-out over the testing years was $2.48 per MWh. The average expected-close out over those years from the GMM was $3.19 per MWh, finding that the ISO's GMM overestimates the close-out by $0.71 per MWh, on average. The ISO determined from these results that its GMM is a reasonably accurate model to use to calculate expected close-outs, as well as strike prices.

Q: How will Market Participants be able to make their own estimates of the strike prices and expected close-out costs for the Day-Ahead Ancillary Services Market?

A: The ISO has publicly shared the mathematical specification of the GMM and the description of the input data—which is either publicly available, or available through subscription from commercial data vendors. If the ISO updates the GMM's specifications or inputs at any point in the future, the ISO will publish any such updates on its website and inform Market Participants and stakeholders.

B. BASE STRIKE ADDER

Q: Please explain why the ISO intends to add $10 per MWh to the expected Real-Time Hub Price when setting the strike price.

A: As described in Section V.C of the Testimony of Dr. Matthew White, the strike price will impact both consumers' costs and Day-Ahead Ancillary Services sellers' incentives to ensure their resources are able to perform. When the ISO first proposed to procure ancillary services Day-Ahead as part of its Energy Security Improvements ("ESI") project, NEPOOL stakeholders proposed a strike price "adder" as a method of reducing the anticipated costs to consumers.[2] The

[2] The ISO proposed ESI in 2020 as part of the Commission's mandate to address fuel security issues. *See* Compliance Filing of Energy Security Improvements Addressing New England's Energy Security Problems, *ISO New England Inc.*, Docket Nos. EL18-182-000, ER20-1567-000 (filed Apr. 15, 2020). The Commission rejected ESI but stated that the ISO was not barred from proposing day-ahead ancillary services in the future outside of the context of fuel security issues. *ISO New England Inc.*, 173 FERC ¶ 61,106, at P 57 (2020) ("We further note that nothing in this order prohibits ISO-NE from proposing a day-ahead reserves market independent of any proposal to address the concerns at issue here.").

idea was to set the strike price above the expected Real-Time Hub Price as a way of reducing expected close-out costs to Day-Ahead Ancillary Services sellers, and thereby reducing ancillary services costs to consumers. At the time of ESI, the ISO did not support stakeholders' proposed $10 per MWh base strike adder due to initial concerns that the adder would adversely dilute the incentives provided by the close-out charge. Given the filing deadline for ESI, the ISO did not have time to assess the full impact of a base strike adder and whether any impact would be material to the effectiveness of the call-option close-out structure. During development and the presentation of the Day-Ahead Ancillary Services Initiative to stakeholders, however, the ISO was able to perform a more thorough assessment of including a base strike adder. Through this assessment, the ISO concluded that a base strike adder of $10 per MWh would not materially reduce resources' incentives under the call option settlement.

Q: What do you mean by resources' incentives under the call option settlement?

A: Conceptually, a resource's incentive is equal to the difference in the Day-Ahead Ancillary Services seller's expected net Real-Time settlement if its resource performs (when needed) in Real-Time, versus if it is unable to perform. By design, a resource that is not able to perform will face greater expected close-out charges (based on the replacement cost of energy), and will face a lower (*e.g.,* a loss in its) net Real-Time settlement; in contrast, a resource that is able to perform will have a higher (*e.g.,* a profitable) expected net Real-Time settlement. As explained in the Testimony of Dr. Matthew White, that difference creates a financial incentive for resource owners to take actions in advance of the operating day to ensure their resources will be able to perform, if needed, in Real-Time.

A variant on this calculation is used in the assessment of the base strike adder. This variant evaluates the incremental incentive provided by the call option's close out charges. Specifically, a resource with a Day-Ahead Ancillary Services award that is not able to perform will face a larger expected close-out charge (based on the Real-Time energy price set by a higher-cost replacement energy resource), relative to the expected close-out charge if it is able to perform (when no replacement resource is needed). Aggregated over time, this difference—which we call the incremental incentive—creates a financial benefit to a Day-Ahead Ancillary Services seller that takes actions to ensure its resource is able to perform when needed, in that it avoids the (greater) financial liability when it is unable to perform.

Importantly, these differences—and therefore resources' incentives—depend on the strike price. A higher strike price will reduce the difference, and therefore reduce a Day-Ahead Ancillary Services seller's incentive to take costly actions to improve its resource's ability to perform. How much the specific \$10 per MWh base strike adder may alter these incentives is an empirical question, and the ISO conducted a quantitative analysis to assess it.

Q: Please explain the assessment that the ISO conducted.

A: The ISO used market simulations and GMM forecasts for the period from January 2019 through December 2021 to estimate resource-level, hourly simulated Day-Ahead Ancillary Services Market outcomes for different base strike adders ($5 per MWh to $40 per MWh in $5 per MWh increments). For the $10 per MWh adder, the ISO evaluated (1) the resources that sell Day-Ahead Ancillary Services whose incentives are impacted by the adder, and (2) the proportion of incentives that are preserved with the adder compared to incentives without the adder (that is, if the strike price is set only to the expected Real-Time Hub Price). The analysis looked at the proportion of incentives "retained" once the adder is used compared to no adder for different system conditions.

To look at the impact of the adder during differing system conditions, the ISO used the GMM-forecasted Real-Time Hub Price as a proxy for high- and low-stress system conditions. Generally, higher forecasted LMPs reflect higher load forecasts, higher fuel prices, more severe weather forecasts, or some combination of the three. Higher expected Real-Time Hub Prices were assumed to reflect high-stress, tighter conditions in the system. Lower expected Real-Time Hub Prices were assumed to reflect low-stress conditions. The ISO analyzed each quintile of hours for expected Real-Time Hub Prices to determine the proportion of "retained" incentives, as well as the top five percent and top one percent of expected Real-Time Hub Prices.

Q: How did the ISO measure retained incentives when conducting this analysis?

A: This was measured by comparing the ratio of two similar calculations, one performed with and the other without the base strike adder. For the first calculation, the ISO estimated, at the individual-resource level and for each hour of the 2019-2021 study period, each resource's incremental incentive with a strike price that included the adder. As explained earlier, in this context its incremental incentive is a resource's estimated expected difference in its close-out charges if it is able to perform (when in economic merit) versus if it is unable to perform.

We then performed the analogous calculations when the close-out charges did not include the base strike adder. Without the adder the strike price was lower, the expected close-out costs were greater (on average), and the incentives were therefore greater.

The proportion of "retained" incentives is the ratio of the first calculation to the second calculation. This ratio was tabulated hourly and for all resources to obtain a measure of the proposed Day-Ahead Ancillary Services Market's incremental incentives to ensure its participants' resources are able to perform (when needed). Conceptually, if the base strike adder has no attenuating effect on incentives, then the ratio would have a value of 1 and imply 100% of the incentives provided with the base strike price would be retained when the base strike adder is also applied.

Q: What were the results of this assessment of the "retained" incentives in different ranges of expected Real-Time Hub Prices?

A: The ISO found that, generally, a $10 per MWh adder has more of an impact on incentives at lower expected Real-Time Hub Prices (*i.e.*, during low-stress conditions) and less of an impact on incentives at higher expected Real-Time Hub Prices (*i.e.*, during high-stress conditions). Specifically, for the lowest quintile of expected Real-Time Hub Prices, where the average expected Real-Time Hub Price in the simulation was $17 per MWh, a strike price reflecting a $10 per MWh base strike adder retains 58 percent of the incentives compared to without the base strike adder. For the highest quintile, where the average expected Real-Time Hub Price in the simulation was $63 per MWh, the strike price reflecting a $10 per MWh base strike adder retains 91 percent of the incentives. For the top five percent of expected Real-Time Hub Prices, where the average expected Real-Time Hub Price in the simulation was $88 per MWh, 95 percent of incentives were retained when applying a $10 per MWh base strike adder. For the top one percent, where the average expected Real-Time Hub Price was $106 per MWh, 94 percent of the incentives were retained when applying a $10 per MWh base strike adder. Table 3 summarizes these results.

Table 3

	Proportion of Remaining Incentives After an Adder						
	E(RT LMP) Quantiles						
	1st Quintile	2nd Quintile	3rd Quintile	4th Quintile	5th Quintile	Top 5 percent	Top 1 percent
$10 per MWh Base Strike Adder	58 percent	68 percent	75 percent	83 percent	91 percent	95 percent	94 percent
E(RT LMP) $ per MWh	$17	$22	$27	$36	$63	$88	$106

What these results reflect is that in low-stress hours, the resources that cleared for Day-Ahead Ancillary Services (in our simulation study) had marginal costs very close to the expected Real-Time Hub Price, and were frequently affected by the base strike adder. In high-stress hours, the resources that cleared for Day-Ahead Ancillary Services had marginal costs far greater than the expected Real-Time Hub Price, and few of those resources were affected by the base strike adder.

Q: Please elaborate further on the base strike adder's different impacts in low-stress and high-stress hours.

A: During low-stress (that is, low load) hours, the supply stack tends to be elastic around the expected Real-Time Hub Price (*i.e.* the supply curve is flatter, and there are many resources with marginal costs around that price), so the system's replacement cost of energy in Real-Time is relatively low. If a resource with a Day-Ahead Ancillary Services award fails to deliver energy in Real-Time, another resource that in all likelihood has a very similar marginal cost in Real-

Time is available to deliver energy. Therefore, the close-out charges will not be affected in a material way. Additionally, the ample supply in these hours means reliability is less of a concern.

In high-stress (that is, high load) hours, supply tends to be inelastic around the expected Real-Time Hub Price (*i.e.*, the supply curve is steeper, and there are few resources with marginal costs around that price), so the system's replacement cost of energy in Real-Time is relatively high. If a resource with a Day-Ahead Ancillary Services award fails to deliver energy in Real-Time, the resource that will deliver energy in Real-Time is likely to have a meaningfully higher marginal cost. In other words, the replacement cost of energy (*i.e.*, the cost associated with the replacement resource) is much higher than the resource's marginal cost, and therefore the difference between the actual Real-Time Hub Price and a strike price set to the expected Real-Time Hub Price would likely be much larger than in low-load hours. This means the resources with a Day-Ahead Ancillary Services award have a stronger incentive to deliver energy in Real-Time than low-load and low-price hours (and, commensurately, a greater financial settlement liability if they do not).

Consequently, the assessment showed that during the system's most crucial hours—those where prices are high and conditions are tight—the $10 per MWh base strike adder has no meaningful impact on the performance of the call option incentive structure. Because the difference between the actual Real-Time Hub

Price and the expected Real-Time Hub Price grows as system conditions become tighter, these results make sense.

Q: Did the ISO analyze other potential base strike adders before choosing the $10 per MWh base strike adder?

A: Yes. The ISO analyzed other fixed base strike adders (from $5 per MWh to $40 per MWh in $5 per MWh increments) and the possibility of a dynamic strike price adder.

Q: Please describe what the ISO concluded regarding other potential adders.

A: The ISO studied the effect on the incentives created by the call option settlement design of different base strike adders, focusing on the aggregate change in the expected close-out charges and proportion of the call option's incremental incentives retained as a result of the adder (as compared to those resulting from the base strike price alone). The exercise consisted of two steps. First, we determined the incentives the call option design creates using the base strike price for different hours. Then, we compared these incentives to those that the call-option design provides with the base strike adder also applied for the same set of hours. By comparing both scenarios, the ISO measured the effect of different base strike adders on the incentives that the call option design provides.

The ISO also evaluated a dynamic base strike adder, which varies with the system conditions. Specifically, the ISO focused on the case of a base strike adder that gradually fades away during the hours with a high expected Real-Time LMP (high-stress conditions). The analysis yielded two key observations. First, the call-option incentives during hours with a high expected Real-Time LMP are those that are the least affected by a base strike adder. Second, determining the threshold where the calculation should switch from a flat to a fading adder was overly complicated.

The ISO concluded that a static $10 per MWh base strike adder balanced the goals of reducing the costs to consumers and maintaining the incentives created by the call option structure during the (high price) conditions when performance matters most. At best, the dynamic adder would have helped better retain incentives in a low-price environment but would have sacrificed savings to load, produced no material improvement in the highest-priced hours, and resulted in a more complex strike price calculation. As explained above, the $10 per MWh base strike adder's impact on incentives in low-price, low-stress conditions is not expected to negatively affect the Day-Ahead Ancillary Services Market's performance or system reliability, and the ISO did not see a benefit to adopting a more complicated dynamic base strike adder when compared to the static $10 per MWh base strike adder presented here.

Q: Will the $10 per MWh base strike adder have an impact on expected and realized close-outs?

A: Yes. The $10 per MWh base strike adder will affect the expected and realized close-outs. The base strike adder has two main effects. First, a resource with a Day-Ahead Ancillary Services award faces a positive close-out charge (*i.e.*, non-zero, as the close-out charge can never be negative under the proposed design) less frequently. If the close-out charge without the adder was $10 per MWh or less, the resource faces no close-out charge with the $10 per MWh adder. Second, when the close-out charge without the adder was greater than $10 per MWh, it still faces a close-out charge, but the amount of close-out is $10 per MWh less. These two effects work to lower the aggregate realized and expected close-out charges in the market.

Without an adder (*i.e.,* using the base strike price alone), the *realized* close-out (*i.e.*, the close-out that would have been historically observed with the strike price set at the GMM's expected Real-Time Hub Price) is positive about 51.4 percent of the time in the Impact Assessment study period of 2019 through 2021. With a $10 per MWh base strike adder, the realized close-out charge is positive in only 16.5 percent of hours. The lesson we draw from this comparison is that a resource with a Day-Ahead Ancillary Services award faces a positive close-out charge much less frequently with a base strike adder than without.

The dollar amount of close-out charge is also smaller with the $10 per MWh base strike adder. With the base strike price set at the GMM's expected Real-Time Hub Price, the average *realized* close-out charges were $2.48 per MWh and $5.52 per MWh with and without a base strike adder, respectively, in the study period of 2019 through 2021. The average *expected* close-out charges from the ISO's GMM are $3.19 per MWh and $5.56 per MWh, with and without a base strike adder, respectively, for the same study period. The aggregate effect of the base strike adder on expected costs to consumers are discussed in detail in the Testimony of Benjamin Ewing.[3]

Q: You mentioned that the base strike adder's impact on incentives are not a concern in low-price environments when there is ample supply. What will the ISO do if supply tightens generally in the market, either due to retirements or a large increase in load?

A: Predicting the impact of a $10 per MWh base strike adder on call option incentives in a generally tighter market requires an understanding of how the supply tightens. In particular, it requires understanding the number of potentially marginal resources and the various marginal costs associated with such resources. Accurately estimating, on a prospective basis, whether a tightening of the market significantly alters the $10 per MWh base strike adder's impact on call-option

[3] For further details about the ISO's Impact Assessment, including how the assessment was designed and conducted, please see Section IX of Mr. Ewing's testimony.

incentives would require more detailed information on these specific changes in the resource mix and resource's marginal costs.

Nevertheless, the ISO intends to assess the impacts and effectiveness of the $10 per MWh base strike adder as part of its periodic review of the effectiveness and functioning of the proposed Day-Ahead Ancillary Services Market. If circumstances change in such a way as to suggest that the adder should be either adjusted or eliminated, the ISO will bring the issue forward with stakeholders and discuss alternative adder designs.

IV. DAY-AHEAD ANCILLARY SERVICES OFFER FORMULATION

Q: What are you referring to when you discuss offer formulation in relation to the ISO's auction-based markets?

A: Offer formulation refers to how the ISO expects its Market Participants to calculate competitive offer prices for the various products they offer to the market. Specifically, the ISO determines what offer formulation should look like under competitive market conditions for the product or service being offered, which I will refer to as competitive offer formulation. Competitive offer formulation underpins the ISO's market-power mitigation design in the proposed Day-Ahead Ancillary Services Market.

Q: For auction-based markets, like the ISO's energy markets and proposed Day-Ahead Ancillary Services Market, what does competitive offer formulation look like?

A: In an auction-based market that reflects competitive conditions, sellers will formulate their offers by setting their offer prices at a level at which they would be indifferent between selling that certain quantity of the product or service and pursuing the next best alternative. Namely, the resource's offer should allow it to (1) recoup the costs it incurs because it sells Day-Ahead Ancillary Services and (2) be no worse off, in expectation, than the next best alternative. As a result, sellers formulate competitive offers such that they are able to recover the cost of providing that product or service, including the opportunity cost of not pursuing the next best alternative. Put another way, a seller will formulate its offer using the costs it could incur (including opportunity costs) as a result of providing the product or service, and could be avoided otherwise. If these avoidable costs are uncertain, the seller also may build into its offer price a risk premium that accounts for the potential that avoidable costs might exceed what the seller predicts such costs will be.

Q: How does competitive offer formulation work in ISO's current energy markets?

A: In the ISO's Day-Ahead and Real-Time energy markets, the Market Participant generally is expected to submit offers that reflect the resource's costs to provide energy in a given hour. Costs reflected in the offer are incremental operating costs, such as fuel costs, variable operating and maintenance costs, and certain opportunity costs, incurred by the resource to provide energy. These avoidable costs reflect the resource's variable short-run costs, as distinct from non-avoidable (in the Day-Ahead and Real-Time timeframes) long-run costs such as a generator's capital costs. These avoidable-cost based offers would be the type of offers expected in any auction-based, competitive market.

Q: In the proposed Day-Ahead Ancillary Services Market, how are Market Participants expected to formulate their offers?

A: Market Participants are expected to formulate their offers using the avoidable costs of providing any of the four Day-Ahead Ancillary Services products during the hour of the Day-Ahead Ancillary Services Offer.

Q: What are the avoidable costs upon which the ISO expects Market Participants to formulate competitive Day-Ahead Ancillary Services Offers?

A: The avoidable costs that Market Participants will incur when providing Day-Ahead Ancillary Services are: (1) the avoidable close-out charge associated with a Day-Ahead Ancillary Services obligation (if any), and (2) the avoidable cost of actions that a resource may take to procure fuel or charged energy between receiving the Day-Ahead Ancillary Services award and the hour of the Operating Day for the award (if any). Market Participants, when formulating competitive offers, should reflect their expectations of these two types of costs.

Importantly, all sellers of Day-Ahead Ancillary Services face a potential close-out charge, and any close-out charge is a cost common to all technology types that sell Day-Ahead Ancillary Services. Not all technology types, however, will experience incremental fuel or energy charging costs between the time of receiving the Day-Ahead Ancillary Services award and the hour of the Operating Day associated with that award. With oil-fired resources, for example, fuel procurement costs will be sunk costs by the time the resource receives a Day-Ahead Ancillary Services award for the next Operating Day. Only natural gas fired resources and storage resources (pumped storage hydro, grid-connected batteries, *etc.*), for which fuel and input energy (*i.e.,* storage) decisions can be easily made after the Day-Ahead Market clears, will experience these avoidable input-energy related costs.

Competitive offers for Day-Ahead Ancillary Services should be made based on resources' expectation of the avoidable costs above. That is, a competitive offer for Day-Ahead Ancillary Service includes the *expected* close-out charge and *expected* avoidable incremental fuel or energy charging costs. To the extent that close-out and avoidable incremental or energy charging costs are uncertain, a competitive offer also includes a risk premium.

Q: Please elaborate on the expected close-out cost and why such cost will be common to all technology types.

A: As explained in the Testimony of Matthew White, the call-option settlement includes a charge to resources with Day-Ahead Ancillary Services awards that equals the positive difference between the Real-Time Hub Price and the strike price for the hour of the award. Namely, whenever the Real-Time Hub Price exceeds the strike price, the resource will be charged the difference. If the Real-Time Hub Price is equal to or less than the strike price, then the close-out charge is zero. The elements that make up the close-out charge, Real-Time Hub Price and the strike price, are common across all resources and are not resource dependent. Hence, the expected close-out charge—which is simply the expected value of the close-out charge taking into account a set of potential Real-Time Hub Prices with varying likelihoods—is also not resource dependent and is common across resources.

Q: Would you please illustrate the expected close-out cost using an example?

A: Yes. Here I provide a simplified example of the expected close-out cost for one hour of the Operating Day. In this example, there are equal probabilities (one-third each) that demand during that hour will either be low, medium, or high. If the demand is low in Real-Time during that hour, the Real-Time Hub Price will be \$15 per MWh. If the demand is medium, the Real-Time Hub Price will be \$84 per MWh. If the demand is high, the Real-Time Hub Price will be \$144 per MWh. This scenario is summarized in Table 4 below:

Table 4

		High Demand	Med. Demand	Low Demand
[1]	RT LMP ($ per MWh)	$144	$84	$15
[2]	Scenario Likelihood	1/3	1/3	1/3
[3]	Expected RT LMP ($ per MWh)	$81		
[4]	Strike Price ($ per MWh)	$91		

The expected Real Time Hub Price is calculated as the mathematical expectation of Real-Time Hub Price, weighed by the likelihood of each scenario. In this example, it will be $81 per MWh (the sum of one-third multiplied by each of three equally likely Real-Time Hub Prices). As explained in Section III of my testimony, the ISO will announce a strike price of $91 per MWh in this example, which is the sum of the expected Real-Time Hub Price of $81 per MWh (*i.e.*, the base strike price) and the $10 per MWh base strike adder.

To determine the expected close-out charge for resources with Day-Ahead Ancillary Services awards during that hour in this simplified example, we must look at the weighted, positive difference between each of the three potential Real-Time Hub Prices and the announced strike price of $91 per MWh. The close-out charge if demand is low or medium will be $0 per MWh, because there is no close-out charge when the Real-Time Hub Price does not exceed the strike price. The close-out charge if demand is high will be $53 per MWh because of the positive difference between $144 per MWh and $91 per MWh. Because each demand scenario has an equal, one-third probability of occurring, the overall expected close-out charge for resources with Day-Ahead Ancillary Services awards during that hour will be $17.67 per MWh.

Table 5

		High Demand	Med. Demand	Low Demand
[1]	RT LMP ($ per MWh)	$144	$84	$15
[2]	Scenario Likelihood	1/3	1/3	1/3
[3]	Expected RT LMP ($ per MWh)	$81		
[4]	Strike Price ($ per MWh)	$91		
[5]	Close-out Charge	$53	$0	$0
[6]	Expected Close-out ($ per MWh)	$17.67		

For this hour, $17.67 per MWh would be the expected close-out cost that resources with a Day-Ahead Ancillary Services award would build into their Day-Ahead Ancillary Services Offer prices. Assuming that the resource incurs no other avoidable costs and does not seek a risk premium, both of which I will discuss more below, the resource would need to offer $17.67 per MWh to expect to break even. Again, this is a simplified example that does not take into account the complex modeling required to estimate Real-Time Hub Prices and determine strike prices, but it serves to illustrate how the expected close-out is calculated and its incorporation into a competitive offer.

Q: Given the complex modeling involved, how are Market Participants expected to calculate expected close-out costs in order to formulate their offers?

A: As explained in Section III of my testimony, the ISO will make available to Market Participants its strike price estimation algorithm from the GMM. The ISO's mathematical algorithm will also make it possible for Market Participants to estimate expected close-out costs before submitting their Day-Ahead Ancillary Services Offers. As explained above, expected close-out costs are dependent on expectations about possible Real-Time Hub Prices and are not resource-specific, and the ISO's algorithm will generate the same expected close-out cost in a given hour for all resources with Day-Ahead Ancillary Services awards. The ISO will also publish its estimated expected close-out cost for a given hour, referred to as the Day-Ahead Ancillary Services Expected Close-Out Component, in the system available to Market Participants for submitting energy and ancillary services offers, eMarket. Market Participants will not need to run the ISO's algorithm themselves to determine an expected close-out cost to formulate their offers.

Resources are also able to develop their own models to determine expected Real-Time Hub Prices and expected close-out costs, and rely on those models when making their offers. As explained further below in Section VI, however, for mitigation purposes, such models will need to be reviewed by the Internal Market Monitor ("IMM") as part of the consultation process if the resource would like to rely on the model to make offers when the prices exceed the Day-Ahead Ancillary Services conduct test threshold.

Q: How does the ISO expect Market Participants to formulate their offers when close-out costs must be estimated prior to the time Day-Ahead Ancillary Services Offers are due, and may not equal actual close-out costs?

A: As is true for any predictive model, the ISO's algorithm cannot predict with certainty Real-Time Hub Prices and close-out costs. The ISO expects that some, but not all, Market Participants will build a risk premium into their Day-Ahead Ancillary Services Offers to account for this uncertainty. As explained further below in Section VI.B, the ISO's mitigation design for the Day-Ahead Ancillary Services Market uses a conduct test that allows resources to submit offer prices that are twice the ISO-determined Expected Close-Out Component, primarily to account for a reasonable range of risk premiums that Market Participants may wish to include in their offer prices.

Q: Please elaborate more on fuel and charged energy costs and why such costs are not common to all technology types.

A: Some, but not all, resources will incur incremental fuel or charged energy costs when taking on a Day-Ahead Ancillary Services award that could be avoided without such an award. As explained in the Testimony of Matthew White, a resource with a Day-Ahead Ancillary Services award for a given hour has incentives to be prepared to produce energy (if needed) in real-time to cover the Day-Ahead Ancillary Services award. For natural gas fired resources this will require procuring fuel for that hour, and for storage resources this will require charging a battery or filling a reservoir, in order to be prepared to produce energy during the award hour. These preparations in advance of the Operating Day may also yield savings to the resource, relative to procuring fuel or charging energy during the Operating Day, and these savings may also impact a competitive Day-Ahead Ancillary Services offer. As explained below, for other resources, like oil-fired resources, the cost of procuring fuel to be prepared to produce energy in real-time is a sunk cost by the time the resource receives its Day-Ahead Ancillary Services award.

Q: For a natural gas-fired resource, how would a Market Participant calculate the avoidable input costs for the resource?

A: Regarding the procurement of fuel to cover Day-Ahead Ancillary Services awards, natural gas-fired resources are expected to incur avoidable fueling costs because of the nature and timing of natural gas procurement. A natural gas-fired resource, once it has learned that it has a Day-Ahead Ancillary Services award, can make a timely nomination of natural gas day-ahead for the hour of the award in order to cover the award. This is because the Day-Ahead Energy Market in New England is cleared each day in advance of the natural gas pipelines' timely nomination deadline.

Importantly, the cost of purchasing and nominating gas day-ahead could potentially be avoided if the resource does not receive a Day-Ahead Ancillary Services award. Thus, its day-ahead fuel cost may be an incremental cost to the resource resulting from its Day-Ahead Ancillary Services award, and that should be reflected in a competitive offer.

Q: Are there other factors affecting avoidable costs for gas-fired resources?

A: Yes. The true expected cost of day-ahead natural gas nomination is impacted by the uncertainty over whether the resource will be needed to produce energy in Real-Time during the hour of the Day-Ahead Ancillary Services award. In the circumstance where the resource nominates natural gas day-ahead to cover its award and does not produce energy in Real-Time because it is out of merit for energy during that hour, the resource may recoup some of its fuel procurement costs by selling its unused natural gas (likely at a loss) intraday. When the resource is in merit in Real-Time and does sell energy during that hour, the resource could experience a cost savings because it will have already purchased gas day-ahead rather than at potentially higher intraday prices to produce in Real-Time. Thus, the net expected cost of procuring natural gas to cover the Day-Ahead Ancillary Services award will be (1) the expected loss, if any, from nominating natural gas day-ahead net of any gains by the resale of the natural gas intraday if the resource is not in merit for energy in Real-Time; minus (2) the expected savings experienced by nominating gas day-ahead compared to the likely higher cost of intraday nomination when the resource is in merit and called on to produce energy in Real-Time. Simply put, the avoidable fuel cost for a natural gas resource is the cost—including the opportunity cost—of procuring natural gas prior to the Operating Day instead of deferring such procurement to the Operating Day as a result of receiving a Day-Ahead Ancillary Services award.

Q: Please provide an example that illustrates the expected cost of procuring natural gas to cover the Day-Ahead Ancillary Services award.

A: Building on the simplified example above, I can illustrate the avoidable costs involved using two examples: in Case I, the natural gas-fired resource does not have a net avoidable fuel cost associated with the Day-Ahead Ancillary Services award; in Case II, it does. Both examples presume, in accordance with the incentives created by the call-option settlement structure described in the Testimony of Matthew White, that the resource (1) has a Day-Ahead Ancillary Services award and (2) has procured natural gas through a Day-Ahead timely nomination to cover that award. The inquiry presented by the example is a consideration, then, of whether that day-ahead procurement of natural gas would have occurred independent of the Day-Ahead Ancillary Services award. To determine this, we need to consider the expected profit of selling energy in Real-Time when procuring gas day-ahead.

Assume for both cases below the same expected Real-Time prices above in Table 5. Next, assume a natural gas fired resource with a heat rate of 8 MMBtu per MWh is able to procure next-day delivery of gas at $4.00 per MMBtu. Therefore, if the resource buys gas day-ahead to cover its Day-Ahead Ancillary Services award, it will incur a cost of $32.00 per MWh. We also need to consider the likelihood that the resource will be in merit in Real-Time, and the possibility that the resource might otherwise resell its gas intraday if not called on to produce energy in Real-Time.

To do so, we need to make some further assumptions in both cases about the price of natural gas intraday. Natural gas prices tend to have a direct relationship with Real-Time LMPs in New England's energy markets. When system conditions are tight and demand is high, both LMPs and natural gas prices tend to be high. When system conditions are not tight and demand is low, both LMPs and natural gas prices tend to be lower. Therefore, natural gas prices are usually low under those same conditions when the resource is less likely to be called on to produce in Real-Time. In these situations, a resource ends up selling the natural gas it bought in the day-ahead timeframe at a lower price during the intraday nomination cycle (which takes place on the Operating Day) compared to the price it initially paid to buy the natural gas in the day-ahead timeframe.

Case I: Gas resource does not have a net avoidable fuel cost

This example illustrates the case in which a resource would find it most profitable to procure natural gas in the day-ahead timeframe irrespective of its Day-Ahead Ancillary Services award. As a result, as illustrated in the example, its avoidable fuel cost of Day-Ahead Ancillary Services is zero.

To continue the example using the Real-Time LMPs from Table 5, we will now also assume that natural gas prices intraday for the high-demand, medium-demand, and low-demand scenarios are expected to be $7.00 per MMBtu, $3.50 per MMBtu, and $2.00 per MMBtu, respectively. Whether the resource resells at any of these prices depends on whether it is dispatched in Real-Time to produce energy.

Table 6

		Units	High demand	Medium demand	Low demand
[1]	Electricity Price (RT)	$ per MWh	$144	$84	$15
[2]	Gas Price (day-ahead)	$ per MMBtu	$4.00	$4.00	$4.00
[3]	Gas resource's fuel cost (day-ahead nomination)	$ per MWh	$32.00	$32.00	$32.00
[4]	Gas Price (intraday)	$ per MMBtu	$7.00	$3.50	$2.00
[5]	Gas resource's fuel cost (intraday nomination)	$ per MWh	$56	$28	$16

For simplicity and the ease of illustrating the avoidable fuel costs associated with a Day-Ahead Ancillary Services offer, assume that the resource can sell natural gas into the intraday market at the same prices at which it can purchase intraday. In other words, the bid-ask spread is zero in intraday gas procurement. With this assumption, the competitive energy offers for the gas resource in the three demand states are simply its heat rate of 8 MMBtu per MWh multiplied by the intraday gas price. During the Operating Day, the amount the resource paid to procure natural gas ($4.00 per MMBtu) before the Operating Day becomes a sunk cost. Consequently, its Real-Time energy offers will be determined based on the opportunity cost of the natural gas procured in the day-ahead market. That is its "next best alternative" if it does not sell energy in Real-Time. For example, when the price of natural gas is $7.00 per MMBtu in the high demand scenario in Real-Time, if the resource does not operate in Real-Time (for any reason), we assume it would sell the natural gas it procured in the day-ahead timeframe at the intraday gas price of $7 per MMBtu (or equivalently, $56 per MWh for a resource with the heat rate of 8 MMBtu per MWh).

The results are in row 5 of Table 6 above. Offers in this row represent the "next best alternative" (the opportunity cost) for the resource if it does not sell energy in Real-Time.

Expected profit from procuring fuel in the day-ahead timeframe

First, we consider the scenario where the resource procures fuel day-ahead at the price of $4.00 per MMBtu for a cost of $32.00 per MWh. In this scenario, the resource would expect to clear the Real-Time Energy Market for that hour in the high-demand and medium-demand scenarios because the expected clearing prices in those two scenarios, $144 per MWh and $84 per MWh, both exceed the corresponding Real-Time energy offers of the resource (given natural gas prices) in the relevant scenarios (shown in row 5 of Table 6 above). In the low-demand scenario, however, the resource does not run. Here it is unable to sell the natural gas it purchased before the Operating Day for $4.00 per MMBtu, because the intraday gas price is now lower. In this scenario, the resource's "next best alternative" is to sell the natural gas at the intraday gas price of $2.00 per MMBtu (or equivalently, $16.00 per MWh for a resource with the heat rate of 8 MMBtu per MWh), thereby recouping half of its day-ahead fuel cost. In this low-demand scenario, the resource's net fuel procurement cost becomes:

$32 per MWh *paid day-ahead for gas* – $16 per MWh *sale of gas intraday* = $16.00 per MWh.

Ultimately, in this low-demand scenario, the resource experiences a net loss of $16.00 per MWh because it was not in merit for Real-Time energy, and there are no revenues to offset the $16.00 per MWh net fuel procurement cost.

In the other two demand scenarios, the resource is in-merit and, although it incurs a fuel cost, it will a make profit:

- in the medium-demand scenario:

  $84 per MWh *Real-Time LMP* – $32 per MWh *paid Day-Ahead for gas* = $52 per MWh;

- in the high-demand scenario:

  $144 per MWh *Real-Time LMP* – $32 per MWh *paid day-ahead for gas* = $112 per MWh.

As noted above in Table 6, we assume a one-third probability that any of the three scenarios may occur. With these assumptions, the $16.00 per MWh loss in the low demand scenario is offset by the profit the resource makes in the other two scenarios. Across the three scenarios, accounting for their equal probability, the expected profit from procuring fuel on a day-ahead basis is:

$$\tfrac{1}{3} \times (-\$16) + \tfrac{1}{3} \times \$52 + \tfrac{1}{3} \times \$112 = \$49.33 \text{ per MWh}$$

Expected profit from waiting until the Operating Day to procure fuel

The inquiry as to whether procuring fuel day-ahead is profitable, however, must also consider the profits of the alternative in which the resource does not procure natural gas day-ahead, and instead waits until the Operating Day to see if it will be dispatched in that same hour. With the resource's heat rate of 8 MMBtu per MWh, the cost of intraday gas for the resource in the high-demand, medium-demand, and low-demand scenarios would be $56.00 per MWh, $28.00 per MWh, and $16.00 per MWh, respectively. Assuming again that the resource's Real-Time energy offer price is based on its intraday cost of fuel, the resource would be dispatched to supply energy in the high- and medium-demand scenarios, but not the low-demand scenario. Thus, the resource can expect a Real-Time fuel procurement cost of $0 per MWh in the low-demand scenario because it would not produce energy in Real-Time and would not need to procure fuel intraday. In the other scenarios, the resource's profit is:

- in the medium demand scenario:

  $84 per MWh *Real-Time LMP* – $28 per MWh *paid intraday for gas* =

  $56 per MWh; and

- in the high demand scenario:

$144 per MWh *Real-Time LMP* – $56 per MWh *paid intraday for gas* = $88 per MWh.

Therefore, resource's expected profits from the procurement of gas intraday is:

$$\tfrac{1}{3}\times \$0 + \tfrac{1}{3}\times \$56 + \tfrac{1}{3}\times \$88 = \$48 \text{ per MWh}$$

Calculation of avoidable input cost

The expected profits that the resource would make is smaller with intraday gas procurement. Thus, the resource is better off procuring gas in the day-ahead timeframe and does not face lost profits from postponing the fuel procurement to intraday.

Consequently, the resource has a rational incentive to procure fuel day-ahead for the purpose of participating in (and profiting from) sales of energy in the Real-Time market, independent of any Day-Ahead Ancillary Services award for those same MWhs. The incremental fuel cost, also known as the avoidable fuel cost, associated with the Day-Ahead Ancillary Services award, therefore, is zero.

Case II: The gas resource faces positive net avoidable cost of procuring fuel day-ahead

In this second case, we illustrate how a gas resource can face a net cost associated with procuring fuel in advance of the Operating Day, and therefore has a non-zero avoidable input cost that should be reflected in its competitive Day-Ahead Ancillary Services Offer.

To illustrate how a gas resource can face a net cost of procuring fuel in advance of the Operating Day, we modify the intraday gas prices from the values assumed in Case I previously. Specifically, instead of $7.00 per MMBtu, we assume that the intraday gas price in the high demand state of the world is $5.50 per MMBtu. Consequently, the resource's competitive Real-Time energy offer in the high-demand scenario—assuming it re-offers competitively based on the intraday price of fuel—is $44.00 per MWh instead of $56.00 per MWh in the earlier example. Everything else remains the same as in Table 6. The relevant information for this Case II is summarized for convenience in Table 7.

Table 7

		Units	High demand	Medium demand	Low demand
[1]	Electricity Price (RT)	$ per MWh	$144	$84	$15
[2]	Gas Price (day-ahead)	$ per MMBtu	$4.00	$4.00	$4.00
[3]	Gas resource's fuel cost (day-ahead nomination)	$ per MWh	$32.00	$32.00	$32.00
[4]	Gas Price (intraday)	$ per MMBtu	$5.50	$3.50	$2.00
[5]	Gas resource's fuel cost (intraday nomination)	$ per MWh	$44	$28	$16

Expected profit from procuring the fuel in the day-ahead timeframe

The expected profits of the gas resource from procuring fuel in the day-ahead timeframe is unchanged from the earlier example, and remains $49.33 per MWh.

Expected profit from procuring the fuel during the Operating Day

Because the gas costs and resource's competitive Real-Time energy offers for the low- and medium-demand scenarios do not change from the earlier example, the profits of the resource if it procures fuel intraday for low- and medium-demand scenarios are unchanged from the previous calculations.

In the high demand case, the profit of the resource is slightly higher than before because the intraday gas price is lower than in the earlier example:

$144 per MWh *Real-Time LMP* – $44 per MWh *paid intraday for gas* = $100 per MWh.

This means that the expected profit of the resource if it procures fuel intraday is:

$$\tfrac{1}{3} \times \$0 + \tfrac{1}{3} \times \$56 + \tfrac{1}{3} \times \$100 = \$52 \text{ per MWh.}$$

Calculation of avoidable input cost

This expected profit of procuring natural gas intraday is higher than the expected profits of the resource if it procures the fuel in the day-ahead timeframe. If the resource were to procure fuel day-ahead instead of postponing procurement to intraday, the resource gives up $52 – $49.33 = $2.67 per MWh of expected profits. Thus, taking into account the alternative of procuring intraday, the net fuel cost of the resource to procure fuel day-ahead is $2.67 per MWh.

In this second case, a supplier relying *only* on profit from the Real-Time Energy Market would not choose to procure fuel day-ahead. Instead, the resource would have avoided this net day-ahead fuel cost of $2.67 per MWh and procured fuel intraday, if the medium or high demand scenarios materialize. Consequently, the resource's day-ahead fuel purchase and the additional $2.67 per MWh cost of this purchase is a cost the resource would have avoided but for its Day-Ahead Ancillary Services award. As a result, the net fuel cost of $2.67 per MWh is an avoidable cost incremental to providing Day-Ahead Ancillary Services, and should be reflected in its Day-Ahead Ancillary Services Offer.

Q: Why doesn't an oil-fired resource have an avoidable fuel cost associated with its Day-Ahead Ancillary Services award?

A: Overall, and as shown in the example regarding natural gas resources, fuel costs that are truly incremental to providing Day-Ahead Ancillary Services are costs that the resource would not have incurred but for its Day-Ahead Ancillary Services award. That is, if the resource would have a rational incentive to procure fuel day-ahead *independent* of its Day-Ahead Ancillary Services award, then it would not have avoided the fuel cost without the Day-Ahead Ancillary Services award.

Oil resources do not, and typically cannot, change fuel arrangements and obtain or cancel delivery in response to receiving a Day-Ahead Ancillary Services award. The region's oil resources procure and store fuel well in advance of the Day-Ahead timeframe, to cover potential energy production for a week or more, or for an entire season. The resource incurs the cost of oil procurement independently of any specific Day-Ahead Ancillary Services award, and such cost effectively functions as a sunk cost in relation to covering (that is, being able to operate during the award hour) a Day-Ahead Ancillary Services award.

Although the resource might plan to "designate" a certain amount of oil to cover its Day-Ahead Ancillary Services award, the actual cost of burning that oil (if dispatched) will be covered through its energy offer price and Real-Time sale of energy. Unlike pipeline natural gas—which is delivered to the resource only for a specified timeframe and cannot be used except within the time specified in the nomination process—the unused oil that was "designated" to cover a Day-Ahead Ancillary Services award can be stored and used to produce energy at a future date. In other words, there are no unrecoverable fuel costs associated with covering a megawatt-hour of Day-Ahead Ancillary Services award that an oil resource could have avoided if it were not for the Day-Ahead Ancillary Services award. Thus, oil resources do not have incremental fuel costs associated with their Day-Ahead Ancillary Services awards.

Q: For a storage resource, how would a Market Participant calculate the avoidable input costs for the resource?

A: Similar to the procurement of natural gas, storage resources can make a choice to charge energy prior to the hour of the Day-Ahead Ancillary Services Award in order to be able to produce energy during that hour. A number of factors will impact when it is most optimal for the resource to charge energy prior to the award hour. But the procurement of electric energy to charge (or pump water into a pond) could reflect either of the Case I or Case II conditions I laid out with respect to natural gas procurement above, depending on market conditions.

Specifically, to be an avoidable "input" energy cost incorporated in a competitive Day-Ahead Ancillary Service offer price, the decision to charge energy in one time period for discharge during the hour of the Day-Ahead Ancillary Services award should be one that is dependent on receiving the award. Namely, there should be an actual cost incurred that is incremental to the Day-Ahead Ancillary Services award and not some other incentive, such as expected positive profits from discharging in Real-Time completely independent of the Day-Ahead Ancillary Services award. Simply put, the actual charging cost to the storage resource should be one that the resource would have avoided but for the Day-Ahead Ancillary Services award.

At a deeper level, for storage resources, the expected direct and opportunity costs (*i.e.* lost profits) of charging in advance of the award hour will also depend on electricity prices. To deliver energy in the award hour, the storage resource needs to charge or maintain charge for that hour. Such charging typically occurs in the overnight and early morning hours due to lower energy prices in these hours. This direct charging cost is one of the components that would enter the calculation of the net cost of charged energy. The resource must also consider the cost of electricity in other potential charging hours and the opportunity cost of choosing one particular charging hour over another. It is worth noting that the efficiency by which a storage resource can convert the charged energy into discharged energy—the roundtrip efficiency of the resource—also plays a significant role in charging costs.

Further, the expected cost of charged energy depends on the energy prices for the award hour as well as energy prices for other hours in the Operating Day during which the resource might discharge. For example, if the Real-Time LMP for the award hour is expected to be low, but high for prior hours when the resource might also discharge, and the resource has limited capacity, it may find itself in a situation where it expects to incur costs or lose profits (*i.e.,* incur an opportunity cost) in other hours in order to charge or maintain electric charge for the award hour. The resource is expected to use its charged energy optimally. This means discharging to deliver energy during the Day-Ahead Ancillary Services award hour if this hour is expected to be the highest priced hour, or in another hour when that hour is expected to be the highest priced hour. Either way, the expected revenue of this discharge should enter the calculation of the net cost of charged energy that factors into the resource's Day-Ahead Ancillary Services Offer.

Q: Why aren't other variable operating and maintenance costs considered avoidable costs relevant to a Day-Ahead Ancillary Services offer?

A: To be sure, a resource faces other operating and maintenance costs when it runs in Real-Time. However, the Real-Time operation of the unit (whether or not it will be dispatched in Real-Time, to be more precise) depends on its Supply Offer in Real-Time, not its Day-Ahead Ancillary Services award. It is expected that the operating and maintenance costs incurred only when the resource runs will be reflected in the Real-Time energy offer of the resource, and recovered then. If these costs were reflected in the Day-Ahead Ancillary Services offer as well as in the Real-Time energy Supply Offer of the resource, they would be recovered twice, even though they can be incurred only once (in Real-Time). Put differently, these costs are avoidable with respect to a resource's Real-Time energy award, not its Day-Ahead Ancillary Services award.

Q: You mentioned earlier that resources may include a risk premium in a competitive offer. What is a risk premium, and why is it reasonable to include a risk premium in a competitive offer?

A: A risk premium is an amount incorporated into the competitive offer in addition to the expected costs of selling Day-Ahead Ancillary Services that is intended to reduce the likelihood of a loss. Resources selling Day-Ahead Ancillary Services products face uncertainty regarding the cost to close-out their Day-Ahead Ancillary Services awards and thus some financial risk that the cost of the award will be higher than anticipated. To account for this risk, resources may find it in their economic interest to incorporate a risk premium in their competitive Day-ahead Ancillary Services Offers. As described in Section VI.B below, the ISO's market power mitigation rules are designed to accommodate the reasonable risk premiums that resources may build into their Day-Ahead Ancillary Services Offers.

The uncertainty that resources with Day-Ahead Ancillary Service awards face is conceptually analogous to the uncertainty faced by resources selling Day-Ahead energy. If resources with Day-Ahead energy or ancillary services awards do not deliver energy in the award hour in Real-Time, they will be charged corresponding replacement costs that depend on uncertain (in Day-Ahead timeframe) Real-Time LMPs.

The financial risk of taking on a Day-Ahead Ancillary Services award is not the only consideration in formulating a risk premium amount, however. A resource may also consider the fact that revenues from selling Day-Ahead Ancillary Services reduce its financial risk, relative to selling only Real-Time energy.

Q: How would revenues from selling Day-Ahead Ancillary Services reduce a resource's financial risk relative to selling only energy?

A: If a resource only sells energy, it is subject to the volatility of energy prices. This volatility can create issues for resources that have high marginal costs that do not frequently clear in the Day-Ahead Energy Market, and may sell energy only during high-price periods in Real-Time. Such resource can have volatile energy revenue streams, given the intermittent and inherently volatile nature of high Real-Time energy prices.

In the proposed jointly-optimized Day-Ahead Market, resources with high marginal energy costs that have the fast-ramping, fast-starting capabilities to function as reserves are apt to clear for Day-Ahead Ancillary Services, potentially consistently so. As discussed in Section V.B of the Testimony of Dr. Matthew White, the more consistent source of revenue from the Day-Ahead Ancillary Services Market will generally serve to smooth out these resources' revenue streams over time, thereby serving to "de-risk" their participation in the energy markets. Consequently, this "de-risking" may be a factor in how such resources formulate risk premiums for their Day-Ahead Ancillary Services Offers.[4]

[4] *See also* ISO New England Inc., *Day-Ahead Ancillary Services Initiative (DASI)* (November 10-12, 2022), p. 57-67, available at https://www.iso-ne.com/static-assets/documents/2022/11/a08_mc_2022_11_08-10_dasi_presentation.pptx (explaining, with numerical examples, how selling Day-Ahead Ancillary Services settled as a call option on Real-Time energy is a natural hedge for fast-start resources (or the fast-ramping capability of online resources), and thereby tends to reduce risk for the resources the system relies upon for these capabilities).

V. MARKET POWER ASSESSMENT

A. DESIGN OF THE MARKET POWER ASSESSMENT

Q: What is the basis for the ISO's proposed market power mitigation plan regarding the new Day-Ahead Ancillary Services Market?

A: The ISO designed its proposed market power mitigation rules by conducting a market power assessment to evaluate the existence of pivotal suppliers in the market and to identify hours for which the exercise of market power by a supplier of Day-Ahead Ancillary Services may be possible. Using this information, the ISO designed the conduct and impact test mitigation plan described below.

Q: How did the ISO design its market power assessment?

A: The ISO used a simulation of the proposed jointly-optimized Day-Ahead Market, including Day-Ahead energy, Day-Ahead Ancillary Services products and offers, demand constraints, and the $10 per MWh base strike adder, to conduct its MPA. This MPA used the same market simulator employed for the ISO's quantitative Impact Assessment of the proposed Day-Ahead Market, as discussed in the Testimony of Benjamin Ewing. The simulation relied on existing market data from the years 2016 through 2021, and this became the period considered for the MPA. Using this simulation and assessment period, the ISO isolated the days on which exercises of market power would most likely be possible in the proposed new market to study the potential impacts of various withholding strategies on market clearing prices.

Q: How did the ISO isolate the days on which exercises of market power would most likely be possible?

A: The ISO first determined days on which a pivotal supplier existed in the simulated Day-Ahead Ancillary Services Market, of which there were 31 days. The ISO then determined the days during which oil prices were less than gas prices, of which there were 15 days. The 15 days during which oil prices were less than natural gas prices cover a cold spell during the 2017/2018 winter when system conditions were generally tight. The combined 46 days were then evaluated for the purpose of understanding how various withholding strategies executed in the Day-Ahead Ancillary Services Market might impact prices for both the Day-Ahead Ancillary Services products and for Day-Ahead energy. I will refer to these 46 days as the 46 study days for the MPA.

Q: How did the ISO define a pivotal supplier for the purpose of identifying the 31 days you noted above?

A: The ISO evaluated the total available economic capacity available in the Day-Ahead Energy Market for the period from 2016 to 2021. This is the sum of all offered Economic Maximum Limit (sometimes referred to herein as the "Economic Maximum") values for all units not on outage at the close of the Day-Ahead bidding window for each day. This total was then adjusted for imports and exports by adding the net imports up to the system's external interfaces' Total Transfer Capability ("TTC"). The ISO then subtracted from this total the sum of the Day-Ahead load forecast and the simulated Day-Ahead Flexible Response

Services (that is, ten-minute and thirty-minute reserve products) requirements for each hour of the Operating Day to arrive at the supply margin for each hour of the Operating Day. Finally, the ISO compared the supply margin to the total Economic Maximum of the largest supplier resource portfolio in that hour. Hours where the supply margin was smaller than the largest portfolio—hours in which the largest supplier portfolio is necessary to meet both the load forecast and Day-Ahead reserve requirements—were hours identified by the ISO as having a pivotal supplier in the Day-Ahead Market. The 31 days were days during which there was at least one hour with a pivotal supplier.

Q: Why did the ISO include the 15 days where oil prices were lower than gas prices as MPA study days?

A: Between natural gas and fuel oil, natural gas has typically been the considerably cheaper of the two fuels, especially over the study period. In addition, in New England, natural gas resources are commonly the marginal resources in the Real-Time Energy Market and are in merit when oil-fired resources are not. When natural gas prices in New England surge higher than oil prices, that has indicated the scarcity of natural gas for electric generation and reflects tight system conditions. Thus, the ISO used the inversion of oil and natural gas prices as a proxy for tight system days. When the ISO looked at the 15 days where such an inversion occurred, the days were those during which the region experienced a severe cold snap that extended from December 25, 2017 until January 9, 2018.

Q: What type of withholding strategies did the ISO analyze on the 46 study days?

A: The ISO looked at the following withholding scenarios.

- The ISO first simulated a "no withholding" (*i.e.* competitive) scenario. In this scenario, all available resources in the historical Day-Ahead Energy Market offer their entire Day-Ahead Ancillary Services capability into the market at prices consistent with the competitive offer methodology described in Section IV of this testimony. Namely, simulated competitive offers were determined using expected close-out charges, avoidable natural gas or charged energy costs (depending on the resource), and risk premiums. In this case, the ISO used resources' actual historical Supply Offers for Day-Ahead energy, reflecting submitted energy offer costs and physical capabilities.

- The ISO then simulated withholding in the Day-Ahead Ancillary Services Market by the Market Participant that cleared the most Day-Ahead Ancillary Services awards in the competitive case. Importantly, the ISO simulated withholding by the Market Participant, and not only individual resources, to ensure that a single Market Participant's portfolio of resources was considered when looking at the impact of withholding. This included simulated withholding of the Market Participant's Day-Ahead Ancillary Services cleared capability (in the competitive case) at 10 percent increments up to 100 percent withholding, while keeping all other offers and capabilities at competitive levels. The ISO then repeated this exercise for the participant with the second- and third-largest cleared Day-Ahead Ancillary Services quantities in the competitive case.

- The ISO also evaluated the incentive to withhold capability from Day-Ahead energy or Ancillary Services. To do this, the ISO simulated withholding of capability at 200 MW, 400 MW, and 600 MW levels for the Market Participant that cleared the most energy and Day-Ahead Ancillary Services in the competitive case, while keeping all other offers and capabilities at competitive levels. The ISO then repeated this exercise for the second and third largest Market Participant in terms of combined energy and Day-Ahead Ancillary Services cleared in the competitive case.

- The ISO also performed simulations to evaluate the impact of withholding Day-Ahead energy on Day-Ahead Ancillary Services prices. In this set of simulations, the ISO raised the offer price of energy offered in the simulated Day-Ahead Market to study its impact on Day-Ahead energy and ancillary services clearing prices.

- The ISO also conducted various additional simulations to inform design questions. For example, it performed a simulation to determine whether a Day-Ahead Ancillary Services Offer format that allows separate Day-Ahead Ancillary Offer prices for each product could be used to profitably exercise market power. The ISO performed this simulation by simulating the withholding of ten-minute ancillary service capability at various levels and studying its impact on Day-Ahead energy and ancillary services clearing prices.

In all of these simulations, the ISO studied the changes in the Day-Ahead Market outcomes and examined the incentive to withhold—namely, the profitability to the simulated-withholding Market Participant. The ISO assessed the profitability to the simulated-withholding Market Participant by examining the shifts in revenues and costs related to the sale of Day-Ahead products, along with alterations in its exposure to Real-Time prices. The objective was to understand the implications of these changes across the portfolio of the withholding Market Participant.

Q: Did the ISO distinguish between economic and physical withholding of Day-Ahead Ancillary Services when conducting these simulations?

A: No. The reason is that from a market power simulation standpoint, successful economic and physical withholding have identical impacts on market outcomes. If successful, either form of withholding makes the withheld capability "extra-marginal" in the Day-Ahead Market clearing process.

Q: How did the ISO calculate the simulated competitive offers for conducting the MPA?

A: To construct simulated competitive offers, the ISO determined expected close-out costs and expected avoidable input costs for each resource consistent with the methodology described in Section IV of this testimony. For risk premiums, the ISO estimated a risk premium for each Market Participant that reflected similar risk-return preferences as those demonstrated in the Market Participant's Real-Time energy market participation. Specifically, the ISO looked at historical Real-Time energy offer data from resources during the MPA study period and calculated the risk premiums for Day-Ahead Ancillary Services offers that would result in the same risk-return preferences as evident in their Real-Time energy Supply Offers.

Q: What are the ISO-calculated ranges for risk premiums used in the MPA?

A: The table below summarizes the range of modeled Day-Ahead Ancillary Services offers risk premiums for (a) all offers and (b) only cleared offers, for the competitive case simulations on the 46 days in the MPA study.

Table 8

Percentile	**50**	**75**	**90**	**95**
Risk Premium of all offers (EcoMax Weighted)	$0	$0	0.39 per MWh	$1.40 per MWh
Risk Premium of cleared offers (EcoMax Weighted)	$0	$0	$ 0	$0.29 per MWh

Table 8 shows that for all offers, as well as for all cleared offers, at least 75% have an estimated risk premium of zero. For all offers, at the 90th percentile we estimate positive risk premiums of $0.39/MWh (*i.e.,* the top 10% of all risk premia are $0.39/MWh or more); at the 95th percentile, the risk premiums are $1.40/MWh. Among offers cleared in the competitive-case simulations, the risk premiums are systematically lower, as a higher risk premium tends to make a seller's offer less likely to clear in the jointly-optimized Day-Ahead Market.

B. MARKET POWER ASSESSMENT RESULTS

Q: What did the ISO learn from the MPA?

A: The ISO identified six key findings as a result of its MPA study and simulations.

- The first finding is that pivotal suppliers in the co-optimized Day-Ahead Market, which includes both Day-Ahead energy and Day-Ahead Ancillary Services, will be infrequent.
- The second finding is that the ability to materially raise Day-Ahead energy prices by withholding Day-Ahead Ancillary Services capability is limited.
- The third finding is that, under certain infrequent conditions absent mitigation, a large supplier could profitably raise Day-Ahead Ancillary Services prices by withholding its Day-Ahead Ancillary Services capability.
- The fourth finding is that predicting hours in which withholding results in increased prices, and thus presents a potentially profitable strategy, is difficult for suppliers.

- The fifth finding is that, under certain, highly infrequent conditions and absent mitigation, a large supplier could profitably raise Day-Ahead energy prices by withholding some or all of its *total* energy and ancillary services capabilities.
- The sixth finding is that the price impacts of withholding Day-Ahead Ancillary Services are primarily to Day-Ahead Flexible Response Services clearing prices, and not Day-Ahead energy prices or the Forecast Energy Requirement Price.

Q: Please elaborate further on the ISO's first finding regarding the existence of pivotal suppliers.

A: Using the six years from 2016 through 2021, a co-optimized Day-Ahead Market that includes Day-Ahead Ancillary Services would have had a pivotal supplier in only 144 hours out of 51,876 hours. This amounts to 0.22 percent of hours, and as mentioned above, these hours occurred on 31 days. The net supply margin in these 144 hours ranged from approximately negative 6 MWh to approximately negative 2,900 MWh. The 31 days with a Day-Ahead pivotal supplier were not always associated with Operating Days that demonstrated tight Real-Time conditions, meaning that a negative net supply margin in the Day-Ahead timeframe does not always precede tight Real-Time conditions. The converse was also true. Some days in which the system proved to be very tight in Real-Time were not foreseen as such in the Day-Ahead timeframe. Many of the tight Real-Time days were days in which an unforeseen outage in Real-Time pushed the system into very tight conditions. On days where the Day-Ahead Market did have a pivotal supplier, the majority of hours within that day did not have a pivotal supplier.

The results show that a pivotal supplier in the jointly-optimized Day-Ahead Market occurs infrequently, even with the new ancillary service demand quantities applied as a result of the Day-Ahead Ancillary Services Market.

While instances of pivotal suppliers are infrequent, the Day-Ahead Market is potentially vulnerable to the exercise of market power on these days. Notably, though, days with a pivotal supplier only show the existence of a pivotal supplier in a minority of hours, a fact that the ISO attributes to the Day-Ahead Market clearing engine's ("MCE") ability to schedule resources in a way that would lessen the impact of any withholding in the tight hours. The market clearing engine's ability to substitute certain resources when conditions are tight in the Day-Ahead Market is explained further below.

Q: Please elaborate further on the ISO's second finding regarding the limited ability of suppliers to raise Day-Ahead energy prices by withholding Day-Ahead Ancillary Services.

A: The ISO found that, even when a large ancillary service supplier withholds its Day-Ahead Ancillary Services capability, the impact on Day-Ahead energy prices was limited. As noted previously, we initially examined withholding strategies for the first, second, and third-largest suppliers in 10 percent increments, up to 100 percent. Here and below, I consider 10 percent withholding of Day-Ahead Ancillary Services a "low" level of withholding that is directionally indicative of whether that behavior will tend to raise prices. Across the simulation studies as a whole, when price impacts rose above the levels observed at 10 percent withholding, we tended to find some of the largest profitable impacts in a mid-range of withholding scenarios, commonly in a vicinity of 40 to 50 percent of a suppliers' capability (though not always, as noted shortly). Withholding capabilities in this middle range occasionally results in large price impacts that could offset the lower quantity of sale (compared to the competitive case) to the withholding participants. For this reason, in the discussions below I will focus on the 10 percent and the 40 percent simulated-withholding results, with additional findings from other cases where notable, though my conclusions below reflect the full range of all of our simulation work.

When the largest provider withheld 10 percent of the Day-Ahead Ancillary Services capability that it cleared in the competitive case, Day-Ahead energy prices, calculated as the sum of the Day-Ahead Hub Price and the Forecast Energy Requirement Price, saw an average increase of $0.16 per MWh across the

46 study days, and the largest increase in price in any hour among those days was $58.54 per MWh.[5]

When the largest provider withheld 40 percent of its Day-Ahead Ancillary Services capability, Day-Ahead energy prices saw an average increase of $0.12 per MWh across the 46 study days, and the largest increase in price in an hour on one of those days was $50.14 per MWh. The average impact on Day-Ahead energy prices is generally larger with higher levels of withholding. But as is evident in the comparison of price impacts of 10 and 40 percent withholding above, occasionally price impacts at higher withholding levels are smaller than at some lower withholding levels. This underscores the difficulty of predicting price impacts, discussed further below. The largest average effect on Day-Ahead energy prices was an increase of $0.99 per MWh, when the largest provider withholds 100 percent of its Day-Ahead Ancillary Services capability. It is worth highlighting, however, that successfully increasing clearing prices does not necessarily result in increased profits for the largest provider.

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[5] The results presented here are different from the market power assessment results shared with NEPOOL stakeholders during the January 2023 Markets Committee meeting. *See* ISO-NE Presentation to NEPOOL Markets Committee, *Day-Ahead Ancillary Services Initiative: Mitigation Enhancements for the Co-Optimized Day-Ahead Market* (Jan. 10, 2023), *available at* https://www.iso-ne.com/static-assets/documents/2023/01/a03b_mc_2023_01_10-12_dasi_mitigation_presentation_rev1.pptx. The results presented at that meeting reflected a simulation of the jointly optimized Day-Ahead Market that did not include a strike-price adder. The results presented in this testimony now reflect a simulation that includes the $10 per MWh strike-price adder. Overall, the difference between the two simulations did not impact the ISO's ultimate findings and conclusions resulting from the market power assessment. The simulation that included the strike-price adder was used as the basis for the conduct and impact test thresholds discussed in Section VI below.

Q: Did you observe clearing outcomes by the jointly-optimized Day-Ahead Market in patterns that may tend to attenuate the price impacts of withholding behavior?

A: Yes. Overall, on average, Day-Ahead energy prices move very slightly, even with high levels of ancillary services withholding, and even on days where the Day-Ahead Market has a pivotal supplier. In running the simulations, the ISO observed that, on some days, the MCE, which jointly optimizes the Day-Ahead energy and ancillary service schedules, tends to schedule resources in a way that uses the ancillary services capability within the market most economically, effectively using substitution as a way to efficiently schedule resources and minimize the impact of ancillary services withholding.

The following are some examples of substituting one resource's capabilities for another resource that is being withheld:

- Suppose participants 1 and 2 sell large amounts of Day-Ahead energy and ancillary services under competitive conditions. If participant 1 withholds Day-Ahead Ancillary Services, the Day-Ahead MCE could respond by buying more *energy* from this participant and less *energy* from participant 2 to allow the purchase of more Day-Ahead Ancillary Services from participant 2.
- Suppose participant 1 sells large amounts of Day-Ahead energy and ancillary services, and participant 2 has large non-fast-start capabilities

and is offline under competitive conditions (*i.e.*, not scheduled Day-Ahead to produce energy). In response to withholding of Day-Ahead Ancillary Services by participant 1, the MCE could commit (*i.e.*, schedule) participant 2's resource so that it can then access participant 2's Day-Ahead Ancillary Services capabilities.

- Suppose participant 1 sells large amounts of Day-Ahead energy and ancillary services, and participant 2 has a fast-start unit that is online under competitive conditions (*i.e.*, scheduled Day-Ahead to produce energy). In response to withholding of Day-Ahead Ancillary Services by participant 1, the MCE could turn off participant 2's unit so that it can schedule participant 2's unit to provide Day-Ahead Ancillary Services from the offline state, and schedule participant 1's unit to provide energy in its place.

Additionally, in certain conditions, the Day-Ahead MCE could procure more energy supply capability to satisfy the Forecast Energy Requirement Demand Quantity in place of (withheld) Day-Ahead Energy Imbalance Reserve capability. This would free ancillary service capability to be used to satisfy other Day-Ahead Flexible Response Services requirements, where the freed-up resources were otherwise capable of providing those types of ten- or thirty-minute reserves.

The MCE's substitution of resources in these ways would move the marginal resource for Day-Ahead energy and ancillary services in ways that would be difficult for a Market Participant (without our access to the ISO's joint optimization model) to predict. That is reflected in a finding that, in many simulated hours in all of the withholding scenarios, Day-Ahead energy and ancillary services prices were lower, rather than higher, as a result of simulated withholding.

Q: Please elaborate on the ISO's third finding regarding the ability of large suppliers, under certain, infrequent conditions, to raise Day-Ahead Flexible Services Prices by withholding Day-Ahead Ancillary Services capability.

A: The ISO found that the average impacts of withholding Day-Ahead Ancillary Services on the prices of Day-Ahead Flexible Response Services is larger than the impact on the Day-Ahead Hub LMP or the Forward Energy Requirement Price. Among the various Day-Ahead Flexible Response Services, the ISO observed that the largest impact on Day-Ahead Flexible Response Services is on the Day-Ahead Ten-Minute Spinning Reserves. This is the product that, in general, has the tightest supply (*i.e.*, fewest resources eligible to sell).

When the largest supplier withheld 10 percent of its Day-Ahead Ancillary Services capability, the average and median impact were increases of $0.83 per MWh and $0 per MWh for the Day-Ahead Ten-Minute Spinning Reserve clearing price, respectively. The average price impact for both Day-Ahead Ten-Minute Non-Spinning Reserve and Day-Ahead Thirty-Minute Operating Reserve products was an increase of $0.12 per MWh.

When the largest supplier withheld 40 percent of its Day-Ahead Ancillary Services capability, the average and median impact were increases of $2.06 per MWh and $0.01 per MWh for the Day-Ahead Ten-Minute Spinning Reserve clearing price, respectively. The average price impact on Day-Ahead Ten-Minute Non-Spinning Reserve and Day-Ahead Thirty-Minute Operating Reserve products were increases of $0.20 per MWh and $0.21 per MWh, respectively.

Further, extreme price increases were rare. In all of the simulations where the largest participant was simulated withholding from 10 to 100 percent of its Day-Ahead Ancillary Services (that is, as a percent of the MWh it clears in the competitive case), we found that less than 1 percent of the hours showed a price increase (relative to the competitive case) in excess of $50 per MWh. This is 1 percent of the hours of the 46 study days with relative tight conditions or pivotal suppliers, which is a very small fraction of the total number of days from the 2016-2021 period from which they are drawn.

Much like with the second finding regarding price impacts on Day-Ahead energy prices, impacts on Day-Ahead Ancillary Services prices, overall, were muted. For example, roughly two-thirds of the time, the change in the price of the Day-Ahead Ten-Minute Spinning Reserve product is $0.10 per MWh or less (and negative more than 6 percent of the time). As described above, this is due to the market clearing engine's ability to make efficient substitutions in response to withholding. For example, when the largest supplier of Day-Ahead Ten-Minute Spinning Reserve withholds, in most hours, the market clearing engine is able to schedule a slower-ramping resource to start at a time that creates additional spinning reserves to substitute for the withheld capability of the largest supplier.

Overall, considered with the results described in the second finding, I find that withholding Day-Ahead Ancillary Services capability is not an effective means to exercise market power. Nevertheless, the potential for withholding to raise Day-Ahead Flexible Response Services prices significantly in a small number of tight market condition hours does require, in my view, that the ISO implement a mitigation design that will address such withholding during those hours.

Q: Please elaborate on the fourth finding regarding the challenge of predicting the hours during which Day-Ahead Ancillary Services withholding will result in higher prices.

A: The ISO found that, although there were hours where a large supplier was able to raise Day-Ahead Ancillary Services prices, the hours during which such withholding would raise rather than lower prices are hard to predict. Consider the simulated ancillary services withholding in the Day-Ahead Market for two Operating Days, January 6, 2018 and January 7, 2018. Both were weekend days where oil prices were lower than natural gas prices and there was no pivotal supplier in the Day-Ahead Market, and both days were projected to have similar loads, temperatures, and fuel prices.

Consider, for example, the strategy of withholding 40 percent of Day-Ahead Ancillary Services by the largest ancillary service supplier in the Day-Ahead Market.

On January 6, 2018, this withholding strategy led to a price increase of $77.85 per MWh at hour ending 20:00 for both Day-Ahead Ten-Minute Non-Spinning Reserves and Day-Ahead Thirty-Minute Operating Reserves products. Using the same withholding strategy, these products saw a $72.03 per MWh price increase at hour ending 18:00 on the same day.

On January 7, 2018, however, the same withholding strategy led to very different outcomes: a *decrease* of $48.18 per MWh in the prices of Day-Ahead Ten-Minute Non-Spinning Reserve and Day-Ahead Thirty-Minute Operating Reserve products and a *decrease* of $45.86 per MWh in the clearing price of Day-Ahead Ten-Minute Spinning Reserve product during the hour ending at 19:00.

These results show that it may be difficult for any Market Participant to predict when a withholding strategy might succeed in raising, rather than lowering, a Day-Ahead Ancillary Services product clearing price. The uncertainty of whether withholding will increase or decrease clearing prices, and thus whether withholding will be beneficial or costly to the Market Participant, serves as a partial deterrent to attempts to exercise market power in this way. The explanation for these disparate impacts of simulated withholding on days with similar demand and fuel prices reflects, in no small part, the substitution and changes to unit commitment patterns summarized previously, in response to the withheld supply.

Q: Please elaborate on the ISO's fifth finding regarding the impact of withholding both energy and ancillary services capability by a large supplier in the Day-Ahead Market.

A: The ISO found that withholding of a large supplier's total capability in the Day-Ahead Market, both energy and ancillary services, results in price impacts that, on average, are not large. For example, when the largest seller of combined Day-Ahead Ancillary Services and energy in the competitive case withheld 200 to 400 MW of both its energy and ancillary services capability, the average price impact on the sum of the Day-Ahead Hub Price and Day-Ahead Forecast Energy Requirement Price—the total payment rate to the physical energy resources cleared in the Day-Ahead Market—was an increase of $1.64 per MWh. The impact for withholding 400 to 600 MW was an increase of $3.64 per MWh. To put these impacts in perspective, note that the sum of Day-Ahead Hub Price and Day-Ahead Forecast Energy Requirement Price in the competitive case, on average, was $98.53 per MWh. As with other scenarios, the results include hours where the Day-Ahead energy prices decreased as a result of withholding because of the market clearing engine's substitution of resources.

Generally, because the withheld MWs do not receive any Day-Ahead revenues, the strategy is costly even on days when the system appears tight. Despite this, price impacts in a limited number of hours when the largest supplier withheld 200 to 400 MW of its total capability resulted in increases in the sum of the Day-Ahead Hub Price and Day-Ahead Forecast Energy Requirement Price in excess of $60 per MWh for 2 hours out of 1,128 study hours. These largest price impacts occurred infrequently, primarily on days with exceptionally high gas prices, high Day-Ahead Market prices overall, and tight Day-Ahead system conditions, and on one study day that had a pivotal supplier.

Q: Please elaborate on the ISO's sixth finding regarding the primary impact of Day-Ahead Ancillary Services capability withholding to Day-Ahead Flexible Response Services prices.

A: The ISO found that Day-Ahead Flexible Response Services prices were primarily impacted when Day-Ahead Ancillary Services capability is withheld, with only limited impacts to Day-Ahead energy prices, defined as the sum of the Day-Ahead Hub LMP and the Forecast Energy Requirement Price. As indicated above, on average, more of the price increase from the ancillary services withholding scenarios appeared in the Day-Ahead Ten-Minute Spinning Reserve prices.

For example, the ISO's simulation of 40 percent ancillary services capability withholding by the largest supplier in the Day-Ahead Market showed greater price increases in Day-Ahead Ten-Minute Spinning Reserve prices compared to Day-Ahead Locational Marginal Prices at the Hub. At that level of withholding, 90 percent of the Day-Ahead Ten-Minute Spinning Reserve price impacts were below $9.45 per MWh, whereas 90 percent of the Day-Ahead energy prices[6] impacts were below $0.98 per MWh, respectively.

Generally, the ISO concluded from this sixth finding that withholding in the Day-Ahead Ancillary Services Market had little impact on Day-Ahead Energy prices, and that such withholding would provide little benefit to a supplier's portfolio of infra-marginal energy resources.

Q: What did the ISO ultimately conclude regarding mitigation based upon the six findings described above?

A: The ISO concluded that the jointly optimized (*i.e.* co-optimized) Day-Ahead Market, for the most part, results in competitive market outcomes, even when some large participants withhold significant quantities of Day-Ahead Ancillary Services or capability that can be used to meet Day-Ahead energy and Day-Ahead Ancillary Services requirements. This is due to the adequate supply of resources able to provide both energy and ancillary services, the substitutability of resources

[6] Defined as the sum of the Day-Ahead Hub LMP and the Forecast Energy Requirement Price in this context.

by the Day-Ahead MCE, and the uncertainty of when withholding will result in higher prices rather than lower prices.

However, withholding of Day-Ahead Ancillary Services capability, either combined with the withholding of energy capacity or by itself, can be a successful strategy to raise prices above competitive levels in certain hours. The hours during which Day-Ahead Ancillary Services prices were raised significantly above competitive levels were hours during which system conditions were tight, but such hours were not correlated with the presence of a pivotal supplier in the market.

Consequently, there is no value in creating a mitigation design focused on the existence of a pivotal supplier in the market or another kind of structural analysis of the market. Rather, the ISO has designed a generally applicable conduct and impact test structure that will prevent the effective exercise of market power during those infrequent hours where withholding may result in a profitable increase in market prices for the withholding supplier.

Q: You mentioned earlier that you looked at the profitability of withholding. Did you make any specific findings as to the profitability of a withholding strategy in the MPA?

A: Yes. The main finding is that withholding of Day-Ahead Ancillary Services is, in general, not very profitable and occasionally can lead to decrease in profits, relative to offering competitively. That said, there are infrequent days in the MPA study period when withholding is quite profitable for the withholding Market Participant. Not surprisingly, these days are the same days on which withholding results in large increases in the prices of Day-Ahead energy or Ancillary Services. After all, a large increase in price is necessary to offset the reduction in sales resulting from withholding of supply, and thus a necessary condition for withholding to be profitable.

Q: Did the ISO use the results of profitability assessments to inform the mitigation design?

A: Only insofar as those results confirmed certain Market Participants will have an incentive to engage in withholding strategies under certain market conditions, and that a mitigation design will be necessary to deter such behavior. That said, the ISO's market power mitigation design for the proposed Day-Ahead Ancillary Services Market will not involve considerations as to whether offer behavior flagged as potential withholding is profitable for the Market Participant that engages in such behavior. The ISO's profitability assessments showed scenarios where withholding was not profitable for the Market Participant, but that may not be known *ex ante* to that Participant when it attempts it—and in doing so, the withholding may still produce substantial price increases and, thus, market harm. The ISO did not want a market power mitigation design focused on profitability that might overlook situations where such market harm occurs.

VI. ECONOMIC WITHHOLDING MITIGATION

A. RATIONALE FOR USING CONDUCT AND IMPACT TESTS

Q: Why has the ISO chosen a mitigation design that incorporates conduct and impact tests, as opposed to a structural test-based approach or some other type of design?

A: As described in Section V, the ISO's MPA did not show evidence that structural screens or tests would be particularly useful in helping mitigate the exercise of market power. The MPA showed the existence of a pivotal supplier in the Day-Ahead Ancillary Services Market in a very small number of hours across six years of data, and price impacts from withholding were more of a concern on tight market days that did not have a pivotal supplier than on days where a pivotal supplier existed. In fact, the average price impacts of withholding were larger for tight days with no pivotal suppliers for all Day-Ahead products. The maximum price impacts are also larger in tight, but non-pivotal days of the study period. Overall, the MPA did not reveal any persistent issues with the supply available to the New England region that would have made *ex ante* structural screens useful.

The ISO chose to proceed with a conduct-and-impact test mitigation framework because it helps avoid over-mitigation in the market. Conduct and impact tests evaluate offers to assess whether the supplier is engaged in potentially uncompetitive behavior in a particular instance and mitigates only where the uncompetitive offer would have a meaningful impact on market prices. As described further below, the conduct and impact tests designed for the Day-Ahead

Ancillary Services Market are designed to apply mitigation only in those rare hours where withholding Day-Ahead Ancillary Services in the Day-Ahead Market might result in significant enough price increases to be profitable to the supplier. Comparatively, a conduct-and-impact test framework is more appropriate than a structural test intended to apply in hours with a pivotal supplier, because the ISO's simulations suggest having a pivotal supplier in the Day-Ahead Market is not correlated with a large impact of withholding. A conduct-and-impact test framework is a market power mitigation approach more responsive to the conditions the ISO observed in its MPA.

Q: Please explain, generally, how the conduct and impact tests will apply to Day-Ahead Ancillary Services Offers.

A: At a high-level, the mitigation design consists of two inquiries. The first is the conduct test, which is an inquiry into whether the offer, based on its prices, represents such a deviation from the anticipated resource's competitive offer that it is presumed to be uncompetitive and a potential attempt at exercising market power. The second is the impact test, which is an inquiry into whether, compared to a market composed entirely of competitive offers, the offer contributes to a material increase in Day-Ahead clearing prices. If the offer fails the first test, the conduct test, it is then subject to the impact test. If the offer then fails the impact test, the offer (more specifically, the offer price) is set at the presumed competitive offer price, which the ISO is referring to as the Day-Ahead Ancillary Services Benchmark Level (or simply "Benchmark Level"). The mitigated offer (*i.e.*, offer with the price reduced to the Benchmark Level) is then entered into the market.

B. CONDUCT TEST

Q: Please explain the conduct test the ISO designed for the Day-Ahead Ancillary Services Market.

A: The conduct test sets a threshold price for resources that, if exceeded by any offer price in a Day-Ahead Ancillary Services Offer, flags a presumptive uncompetitive offer. That threshold price is set based on two elements of the costs the ISO anticipates resources will incur in formulating a competitive offer. The first element is the expected close-out charge. Referred to by the ISO as the Day-Ahead Ancillary Services Expected Close-Out Component, the expected close-out charge is a cost anticipated for all resources participating in the Day-Ahead Ancillary Service Market, independent of resource technology type. The commonality of the Expected Close-Out Component to all resources is described at length above in Section IV above. The second element of the threshold price is the fuel or charged energy costs that natural gas resources and storage resources, respectively, may anticipate incurring as a result of taking on Day-Ahead Ancillary Services awards. As described at length in Section IV, this second element, referred to as the Day-Ahead Ancillary Services Avoidable Input Cost (referred to in this testimony, however, only as the "Avoidable Input Cost"), is a cost specific to natural gas-fired and storage resources and may, at times, be zero even for these resource types. Taking these two elements, the ISO will set the conduct test threshold for each resource and each hour of the Operating Day to be the sum of the following:

- the greater of $2 per MWh and 200 percent of the Expected Close-Out Component; and
- 150 percent of the Avoidable Input Cost.

Because the Avoidable Input Cost is presumed to be "zero" for all resource technology types except natural gas-fired resources and storage resources, this means that the conduct test threshold for other resource types is simply two times the Expected Close-Out Component or $2 per MWh, whichever is greater.

1. Expected Close-Out Component

Q: How will the ISO calculate the Expected Close-Out Component of the conduct test threshold price?

A: As I explained in Section III, the ISO uses the GMM to estimate the distribution of the Real-Time Hub Price for all hours in the Operating Day. With the distribution in hand, it determines the Day-Ahead Ancillary Service Strike Price as explained in Section III. The ISO then estimates the Expected Close-Out Component in a conceptually similar method to the one I described in Section IV. The Expected Close-Out Component that the ISO calculates for each hour will be the same for each resource making a Day-Ahead Ancillary Services Offer for that hour because the expected close-out charge is dependent entirely on the relationship between the strike price and Real-Time Hub Price, and is not specific to any particular resource or resource technology type. However, the ISO will include in its calculation of the Expected Close-Out Component what I refer to as a “safety cap” formula that ensures Expected Close-Out Component values are not so high as to effectively eliminate market power mitigation during times of expected high Real-Time Hub Prices that are subject to volatility and increased unpredictability.

Q: Please elaborate on the "safety cap” formula incorporated into the Expected Close-Out Component calculation.

A: As detailed in Section III above, the ISO has developed a statistical model, known as the GMM, to estimate the distribution of Real-Time Hub Prices and compute the expected close-out charge. Although the GMM is a robust model that outperforms other available models in terms of reliably estimating a distribution of Real-Time Hub Prices and close-out charges, the ISO has observed that, in rare stress-testing conditions, the GMM could produce a variance (*i.e.*, a “fat right tail”) for possible Real-Time Hub Price values that can result in a higher expected close-out component than would align with the design of the call-option settlement. Specifically, the expected close-out value could get too close to, or even exceed, the expected Real-Time Hub Price during the same hour when logic indicates it should not. In the ISO’s stress-testing of the GMM, this tended to occur when natural gas prices or forecast load levels were vastly outside of historical observations. To correct for this circumstance, the ISO developed a formula that can serve as a dynamic safety cap.

Q: Please elaborate on what you mean when you say that the expected close-out value could get too close to or exceed the expected Real-Time Hub Price when logic indicates it should not.

A: When Real-Time LMPs are expected to be high, the expected close-out value should not get too close to the expected Real-Time Hub Price or exceed it. A supplier with a Day-Ahead Ancillary Services award will receive a close-out charge only when the actual Real-Time Hub Price exceeds the strike price. Because the strike price will never be less than zero, the maximum actual close-out charge a resource can receive under this design is the actual Real-Time Hub Price (*i.e.*, the actual Real-Time Hub Price minus zero), unless the actual Real-Time Hub Price is negative (in which case the actual close-out is zero). Based on this logic, generating an expected close-out charge that *exceeds* the expected Real-Time Hub Price when Real-Time prices are expected to be generally positive makes little sense. The logical prediction would be an expected close-out charge that is, at most, the same as the expected Real-Time Hub Price in these circumstances. The ISO instead expects that, in most scenarios, the expected close-out charge used by the ISO in determining the Expected Close-Out Component of the conduct test should equal some fraction of the expected Real-Time Hub Price.

Q: Why is capping the Expected Close-Out Component at realistic predictions of actual close-out charges important?

A: First, it is important to reflect an accurate representation of the expected close-out value in line with the fundamentals of electricity markets. Second, capping the Expected Close-Out Component ensures that, particularly during periods of strained conditions (which can amplify the potential for profitable exercise of market power and its detrimental impact on the system), there exists a reasonable cap on conduct test price thresholds. As explained above, conduct test price thresholds are determined using two times the Expected Close-Out Component. When high Real-Time Hub Prices are anticipated, expected close-out charges and conduct test thresholds tend be higher. This is because similar factors drive both high Real-Time Hub Prices and high expected close-out charges. For instance, when the forecasted load is high, the supply curve around the Day-Ahead energy price is typically more inelastic, resulting in a steeper supply curve and greater potential for successful exercise of market power. Allowing a high and unrealistic Expected Close-Out Component to be used to set conduct test thresholds may undermine market mitigation at a time mitigation may be needed the most.

Notably, in the ISO's simulations, the "safety cap" formula value has never been binding (*i.e.*, it *always* exceeded the GMM-determined expected close-out when expected Real-Time Hub Prices exceeded $100 per MWh) for any historical observation in the testing or training data. In other words, in the ISO's testing and training data, the GMM did not produce an unrealistically high expected close-out value that would trigger the application of the safety cap formula. Nevertheless, the ISO believes this "safety cap" formula is an important safeguard to protect against the attempted exercise of market power during times of system stress, should the ISO observe conditions in the future that are beyond the range of the historical data used to develop the GMM expected close-out cost model.

Q: What is the "safety cap" formula, and how does it address this issue?

A: Although the formula itself is more complex, in its simplest terms, the ISO's proposed safety cap is the GMM-calculated expected Real-Time Hub Price multiplied by the historical probability that the Real-Time Hub Price falls below this expected value, with an adjustment to ensure that the "safety cap" value will only override the GMM's expected close-out value when the expected Real-Time Hub Price exceeds $100 per MWh.[7]

To illustrate this simplified version of the "safety cap" formula, consider the example in Table 5 previously introduced in Section IV, which I repeat here for convenience:

[7] The formula is captured in the proposed Tariff language as "the historical average of the estimated likelihood that the Real-Time Hub Price will be equal to or less than its expected value, multiplied by the greater of $100 per MWh and the expected hourly Real-Time Hub Price." *See* Marked Tariff, Section III.A.8.2.1 of Appendix A to Market Rule 1.

Table 9

		High Demand	Med. Demand	Low Demand
[1]	RT LMP ($ per MWh)	$144	$84	$15
[2]	Scenario Likelihood	1/3	1/3	1/3
[3]	Expected RT LMP ($ per MWh)	$81		
[4]	Strike Price ($ per MWh)	$91		
[5]	Close-out	$53	$0	$0
[6]	Expected Close-out ($ per MWh)	$17.67		

Assume that, in this simple example, the expected close-out value of $17.67 per MWh was produced by the GMM (though, in actual application, the GMM would have a much more complex set of variables from which to calculate an expected close-out). In the example, the Real-Time Hub Price falls below its expected value only in the low-demand scenario. That is, the probability of the Real-Time Hub Price being lower than its expected value is one-third. Thus, the "safety cap" value in this example, applying the formula, would be:

(Expected RT Hub Price) × Prob.(RT Hub Price < expected RT Hub Price) =

$81 per MWh × ⅓ = $27 per MWh

The "safety cap" expected close-out value is $27 per MWh, which exceeds the calculated expected close-out of $17.67 per MWh. Consequently, the ISO would not apply the "safety cap" value.[8]

[8] Note that the expected Real-Time Hub Price in this example is $81 per MWh, below the $100 per MWh threshold above which the safety cap formula is applicable. In this example, we calculate the applicable safety cap despite this condition to illustrate the mechanics of the calculations.

Because the “safety cap” relies on expected Real-Time Hub Prices, it is dynamic and responsive to the conditions of the market. It will produce a higher value when the expected Real-Time Hub Price is higher and lower when the expected Real-Time Hub Price is lower.

Q: Please elaborate on the adjustment to the “safety cap” formula that ensures the “safety cap” value is used as the expected close-out value when expected Real-Time Hub Prices exceed $100 per MWh.

A: The “safety cap” formula described in the proposed Tariff language ensures that the expected Real-Time Hub Price must exceed $100 per MWh before it will replace the GMM-determined expected close-out value. That said, even when the expected Real-Time Hub Price exceeds $100 per MWh, the GMM-determined value still must exceed the “safety cap” value before the “safety cap” value is used as the Expected Close-Out Component.

Q: How did the ISO determine the safety cap threshold of $100 per MWh?

A: As mentioned above, actual close-out values should not exceed the actual Real-Time Hub Price unless the actual Real-Time Hub Price is negative, in which case the actual close-out would be zero. To prevent the “safety cap” formula from replacing the GMM-determined expected close-out value when the Real-Time Hub Price could be negative (and thus, the actual close-out will be greater), the ISO built in an expected Real-Time Hub Price threshold sufficiently bounded away from zero. Put differently, the ISO wanted an expected Real-Time Hub

Price threshold in the formula set where the possibility of a negative Real-Time Hub Price is significantly lower than the possibility that the Real-Time Hub Price is positive.

The ISO also wanted the "safety cap" threshold to apply only in extreme cases, namely where a GMM-determined expected close-out value exceeds the expected Real-Time Hub Price during high-priced environments. As explained above, a motivating factor for the application of the "safety cap" formula was to prevent unrealistically high Expected Close-Out Component values that would undermine market power mitigation.

To find a suitable threshold for the application of the "safety cap" value, the ISO tabulated the realized historical Real-Time Hub Prices against the GMM-calculated expected Real-Time Hub Price. The results for candidate thresholds are in the table below:

Table 10

Expected Real-Time Hub Prices	≥$50 per MWh	≥$75 per MWh	≥$100 per MWh
Lowest *observed historical* Real-Time Hub Price	-$27.24 per MWh	$15.30 per MWh	$40.97 per MWh
Number of *observed negative* Real-Time Hub Prices in 10 years of historical data	4	0	0

As shown in the table, observed negative Real-Time Hub Prices sometimes, though rarely, occurred in hours where the expected Real-Time Hub Price exceeded $50 per MWh. And although there were no negative Real-Time Hub Prices observed in hours when expected Real-Time Hub Prices exceeded $75 per MWh, the lowest observed Real-Time Hub Price ($15.30 per MWh) was still low. For expected Real-Time Hub Prices exceeding $100 per MWh, the lowest observed Real-Time Hub Price was $40.97 per MWh. Thus, the observed Real-Time Hub Prices were far enough away from zero such that the ISO is confident a $100 per MWh threshold will prevent the application of the "safety cap" formula when unnecessary.

Q: Why does the conduct test threshold allow for offers that are two times the Expected Close-Out Component?

A: The buffer between the conduct test threshold and the Expected Close-Out Component is intended to accommodate three elements: possible error in estimating resources' close-out costs (*i.e.*, inevitable inaccuracies inherent in predicting close-out values), a reasonable range (variation) of participant expectations of Real-Time outcomes affecting competitive offers, and a reasonable range of risk premiums. The primary driver of the two-times buffer, however, is the third element—allowing Market Participants to include a reasonable range of risk premiums in their offers.

As explained in Section V of my testimony, in ISO's simulations of competitive Day-Ahead Ancillary Service Offer prices, each participant was modeled as having similar risk-return preferences for its Day-Ahead Ancillary Service market participation as it historically has had for its Real-Time energy market participation. This assumption allowed the ISO to calculate risk premiums for each resource's Day-Ahead Ancillary Service Offers that were consistent with the resource's risk preferences shown through its Real-Time energy market participation.

The ISO found that two times the Expected Close-Out Component was sufficient to accommodate almost 97 percent of resources' estimated risk premiums, calculated as described above.[9,10] This includes all competitive offers, including those from resources that did not receive a Day-Ahead Ancillary Services award in the competitive MPA simulation, as well as those that did receive such an award. Two times the Expected Close-Out Components accommodated 99.9 percent of the risk premiums of the offers that cleared in the competitive MPA simulations (*i.e.* received Day-Ahead Ancillary Services awards). Thus, we estimate that this 200 percent range of the hourly Expected Close-Out Component will allow for virtually all competitive offers to participate in the market unimpeded.

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[9] The ISO weighed resources by their Economic Maximum to make them comparable. A 10 MW resource has twice the weight of a 5 MW resource.

[10] When the calculated risk premiums are less than the Expected Close-Out Components, the sum of the two is less than two times the Expected Close-Out Components.

The ISO's analysis showed that accommodating all simulated competitive offers from all resources would require setting the range to more than ten times the Expected Close-Out Component. In light of this and the sufficiency of the 200 percent range to accommodate competitive offers in the ISO's simulations, the ISO determined that allowing for Day-Ahead Ancillary Services Offer prices that are two times the Expected Close-Out Component properly balances over- and under-mitigation concerns.

Q: Why does the ISO have a floor of $2 per MWh for the Expected Close-out Component in the conduct test?

A: With the $10 per MWh base strike adder, there are hours with low expected Real-Time Hub Prices in which two times the expected close-out would produce a very low conduct test threshold price. For example, if the ISO calculated an Expected Close-Out Component of $0.02 per MWh, applying the two-times multiplier will result in a $0.04 per MWh conduct test threshold price for any resource that does not have any avoidable fuel or charged energy costs. This leaves only $0.02 per MWh for other variables that the resource may reasonably consider when making a competitive offer, such as risk premiums or a slight variation in the calculation of the expected close-out charge. The $2 per MWh floor provides the "room" necessary in setting the conduct test threshold to allow these other variables to be accounted for in the participant's competitive offer.

Q: Does the floor of $2 per MWh risk allowing a resource to exercise market power?

A: No. As explained further below, the ISO's modeling shows that expected close-out charges that would result in Expected Close-out Component in the conduct test near or below $2 per MWh occur when the Day-Ahead Market has ample supply of energy and ancillary services. Thus, the ISO expects competitive conditions when the expected close-out charges are below $2 per MWh.

Q: How did the ISO arrive at $2 per MWh as the appropriate floor?

A: Because a floor is only necessary when expected close-out values are so low that two times the value does not provide a sufficient buffer for risk premiums and other considerations, the floor should be set in relationship to low expected close-out values. However, the floor should not be high enough to allow for the unmitigated exercise of market power.

To find a floor value that captured low expected close-out values but would not risk the unmitigated exercise of market power, the ISO examined the lowest 10 percent of GMM-generated expected close-out charges in the study period of 2019-2021. Expected Real-Time system conditions directly correspond to expected close-out charges. The tighter the expected system conditions in Real-Time, the higher the expected close-out charge; the more competitive the expected system conditions in Real-Time, the lower the close-out charge. In other words, more competitive supply for Day-Ahead Ancillary Services correlates with more competitive expected market conditions, and corresponds with lower expected close-out costs.

Thus, to determine the floor, the ISO examined the lowest 10 percent of the expected close-out charges in the 2019-2021 study period, which present very low close-out charges and competitive conditions not susceptible to exercises of market power. The bottom 10 percent of expected close-out charges during this period were $0.90 per MWh or less. The 200 percent range of Expected Close-Out Component corresponding to this cutoff point is 2×$0.90 per MWh = $1.80 per MWh, which the ISO rounded to $2 per MWh to set the floor.

The ISO further analyzed the proposed floor to validate its performance against simulated *realized* close-out charges for hours with the lowest 10 percent of expected close-out charges. The *realized* close-out charges were less than $2 per MWh almost 95 percent of the time. This suggests the *realized* close-out charges in the lowest 10 percent of expected close-out charges rarely exceed the proposed $2 per MWh floor in these circumstances.

Given the above observations, the ISO determined that a $2 per MWh floor is reasonable for the conduct test threshold price for resources with no Avoidable Input Cost when expected close-outs are low.

2. *Avoidable Input Cost*

Q: How does the ISO calculate Avoidable Input Costs for the conduct test threshold?

A: The ISO will calculate Avoidable Input Costs for each hour of the Operating Day for natural gas-fired resources and storage resources, which, as described above in Section IV, are the two technology types that are expected to incur incremental fuel or charged energy costs associated with the Day-Ahead Ancillary Services awards. The ISO-calculated Avoidable Input Costs will be consistent with the principles associated with how it expects resources to incorporate expected natural gas or charged energy costs into competitive offers, as described in Section IV. The ISO has developed a simplified calculation of natural gas procurement costs for gas-fired resources making Day-Ahead Ancillary Services Offers that it intends to use to calculate Avoidable Input Costs for such resources.

Q: Please elaborate on the simplified calculation of natural gas procurement costs that the ISO intends to use to calculate Avoidable Input Costs.

A: As explained at length in Section IV, the avoidable fuel cost for natural gas resources is the portion of the cost of procuring natural gas, including opportunity costs, in the Day-Ahead timeframe that the resource expects it will not recover by selling energy in Real-Time, or by re-selling its nominated natural gas back into the natural gas market in the Real-Time timeframe (*i.e.*, intraday). The ISO uses this principle to calculate the Avoidable Input Cost for natural gas resources, but with some simplifying assumptions necessary to make the calculation consistent across resources and easier to administer.

In applying this principle, the ISO intends to calculate Avoidable Input Costs for natural gas resources using the following methodology. The ISO will first find a resource-specific expected cost of procuring natural gas necessary to supply a MWh of energy by multiplying the gas price (in $ per MMBtu) used to calculate the resource's energy market Reference Levels by the resource's average heat rate (in MMBtu per MWh).[11] The ISO will then subtract the expected Real-Time Hub Price, as determined by the GMM, from the resource's expected cost of procuring natural gas. The difference—if positive—is the natural gas resource's Avoidable Input Cost. This is expressed in the following formula:

$$\text{Avoidable Input Cost} = \max\{0, \text{Cost of Gas Day-Ahead} - \text{Expected Real-Time Hub Price}\}$$

Q: What are the simplifying assumptions the ISO is making when it calculates Avoidable Input Costs for natural gas resources in this way?

A: The ISO is making several assumptions in calculating Avoidable Input Costs for natural gas resources in this way, and using these assumptions derives the final formula above in two steps.

[11] The ISO uses Reference Levels to determine presumptively competitive offers in its energy markets. The Day-Ahead Ancillary Services Benchmark Levels are conceptually similar to the Reference Levels related to energy offers.

The first step and simplifying assumption is that the fuel procured to cover a Day-Ahead Ancillary Service award can lead to two financial outcomes. First, when the resource is in merit in Real-Time, the natural gas will be used to produce energy. Second, when the resource is not in merit in Real-Time, the natural gas will be sold back in the intraday gas market. In either of these outcomes, the resource accounts for the price of intraday natural gas: either as the cost it does not have to pay (first outcome), or direct revenue (second outcome).

Put together with the cost the resource paid in the Day-Ahead timeframe to procure natural gas, the Avoidable Input Cost of the resource would be the price of procuring natural gas in the Day-Ahead timeframe, net of the (expected) price of natural gas in the intraday gas market. With this first simplifying assumption, the avoidable fuel cost can be initially represented in the following formula:

$$\text{Avoidable Input Cost} = \max\{0, \text{Cost of Gas Day-Ahead} - \text{Expected Cost of Intraday Gas}\}$$

As a second step, we make the next simplifying assumption that the expected cost of intraday gas can be expressed using the expected Real-Time Hub Price. Gas-fired generation is marginal for energy (*i.e.*, sets the Real-Time Hub Price) the vast majority of hours annually (83 percent in 2021 and 79 percent in 2022). Assuming that these gas-fired generators are offering consistent with their costs, the expected Real-Time Hub Price serves as proxy for intraday gas procurement.

Consequently, the ISO substitutes the expected Real-Time Hub Price for the expected cost of intraday gas in its formula, resulting in the formula described in my previous answer.

The principal driver for the simplified fuel component formula for natural gas-fired resources is the limited observable intraday gas price data, and using this proxy price allows efficient estimation of intraday gas costs that will be consistent across each natural-gas fired resource.

As noted below, the ISO's 50 percent buffer above the ISO-calculated Avoidable Input Cost allows for variation among the natural gas-fired resource's gas procurement costs. Moreover, this assumption is unlikely to result in Avoidable Input Costs that restrict what a natural gas-fired resource may offer. When natural gas is not the marginal fuel because it is more expensive than the marginal fuel, the expected Real-Time Hub Price is lower than the expected intraday gas price. Thus, the assumption results in an Avoidable Input Cost that is *larger* than if an expected intraday gas price was observed and used.

Q: How does the ISO intend to calculate Avoidable Input Costs for dual-fuel resources capable of burning both natural gas and oil?

A: Note that dual-fuel resources must identify which fuels they intend to use during any given hour in their Supply Offers. If a dual-fuel resource indicates that it intends to use only oil in the hour associated with its Day-Ahead Ancillary

Services Offer, its Avoidable Input Cost will be set to zero, just as with other oil-fired resources. If a dual-fuel resource indicates that it intends to use natural gas for some or all of its production during the hour associated with the Day-Ahead Ancillary Services Offer, the ISO will calculate an Avoidable Input Cost commensurate with the proportion of natural gas the resource would use compared to oil during that hour.

Q: How will the ISO calculate Avoidable Input Costs for storage resources?

A: As mentioned above, the ISO will follow the principles for determining the cost of charged energy described in Section IV. In applying these principles, the ISO will treat the Avoidable Input Cost related to charged energy as having three components. The first cost component is the cost of pumping or charging the storage resource, adjusted for the "round-trip" efficiency of the resource (*i.e.* how many MWh of discharge the resource gets for each MWh of charge, on average). The second is the expected energy revenue in the award hour. This captures the expected revenue a storage device earns in the award hour, conditional on being in merit for energy in the award hour. The third is the expected unused charge value. This captures the value of the stored input energy, if the input energy is not ultimately used during the award hour, which is generally the revenue the resource could earn by discharging in a different hour other than the award hour. Each of these components depends on expectations of the Real-Time Hub Price during the hours of the Operating Day, and the ISO will use the GMM in determining these cost components.

To account for these three costs, the ISO will calculate the cost of charging the storage resource (the first cost component) using the average of the three lowest expected Real-Time Hub Prices estimated by the GMM in the first eight hours of the Operating Day. It will then adjust this value by the round-trip efficiency of the resource, and compare that cost to the expected revenues in the award hour and other potential hours of discharge (the second and third cost components). If the first component above is greater than the sum of the second and third components, then the storage resource's Avoidable Input Cost would include that difference. Otherwise, the storage resource's Avoidable Input Cost will be equal to zero.

The rationale for this is similar to the rationale described in Section IV above as to why a natural gas resource that procures gas day-ahead and has an expected profit (accounting for opportunity costs associated with procuring gas intraday) from Real-Time energy revenues during the hour of the Day-Ahead Ancillary Services award will have a net fuel cost of zero. In the case of the storage resource where expected Real-Time energy revenues in the hour of the award or other hours available for discharge exceed the cost of procuring the charge earlier in the Operating Day, the storage resource can expect a profit from discharging and producing in Real-Time even without its Day-Ahead Ancillary Services award during the same hour. In that circumstance, the resource already has an incentive to charge during those earlier hours of the Operating Day, and it will rationally make the decision to charge completely independent of the need to cover a Day-Ahead Ancillary Services award. In such a circumstance, the net charging cost to providing Day-Ahead Ancillary Services is zero, as no charging costs would be avoided without the Day-Ancillary Services award.

Q: Why does the conduct test threshold allow for offers that are fifty percent higher than the Avoidable Input Cost?

A: Allowing a 50 percent tolerance above the Avoidable Input Cost helps address the limitations and potential for error in estimating input-energy related costs for competitive ancillary services offers. As mentioned above, the methodology for determining Avoidable Input Costs for natural gas resources must make some simplifying assumptions in order to have a methodology that can be both (1) used across different resources and (2) feasible to administer. The methodology for determining Avoidable Input Costs for storage resources has similar limitations. For example, the ISO's methodology effectively assumes that the resource will charge during one of the three hours for which Real-Time LMPs are expected to be lowest during the first eight hours of the Operating Day, but resource practices may vary based on market conditions as the Operating Day approaches and based on other factors. Having a conduct test threshold that allows this level of tolerance above the ISO's Avoidable Input Cost calculation recognizes the unavoidable imperfections of modeling these types of costs.

To determine the tolerance value, the ISO compared the Avoidable Input Cost component of the competitive Day-Ahead Ancillary Services Offers it calculated for natural gas and storage resources that it used in the MPA (as discussed in Section IV of my testimony) to the simplified formulation that will be used for determining Avoidable Input Costs described above. A 50-percent tolerance accommodated more than 99.5 percent of the Avoidable Input Cost components used in the simulated offers that the ISO used in the MPA.

Similar to the discussion on the multiplier to the Expected Close-Out Component, this tolerance covers almost all competitive offers. But raising the tolerance to reflect *all* simulated, competitive Avoidable Input Costs would significantly weaken the mitigation design because it would mean raising the tolerance to more than 10 times the simplified formulation for Avoidable Input Cost described.

Pushing the tolerance lower is not advisable either. Natural gas prices can be volatile in New England, and thus a lower tolerance could prevent competitive offers, especially when market conditions are tighter, from participating in the Day-Ahead Market at their competitive Day-Ahead Ancillary Services offers. As a result of the considerations noted above, the ISO determined that the 50-percent tolerance strikes a reasonable balance between over- and under-mitigation for natural gas and storage resources.

Q: Did the ISO conduct any analysis to validate that its proposed conduct test threshold methodology is unlikely to either over-mitigate or under-mitigate Day-Ahead Ancillary Services Offers?

A. Yes. The ISO used its proposed conduct test threshold methodology and applied it in its proposed Day-Ahead Market simulations to compare how many simulated competitive Day-Ahead Ancillary Services Offers were flagged as violating the threshold during the 46 study days of the MPA. There are approximately 251,000 total *accepted* offers in the 46 tight days (*i.e.* 1,128 hours) of MPA. These offers are equal or below the highest Day-Ahead Ancillary Services accepted offers in the corresponding hour. Out of these accepted offers, only 238 offers in 11 hours exceed the ISO's proposed conduct test threshold level. This is a false positive rate of less 0.1 percent.

Q: Ultimately, what happens when a Market Participant submits a Day-Ahead Ancillary Services Offer that exceeds the conduct test threshold?

A: In such cases, the offer is flagged and then included as part of the impact test market runs, which are used to determine whether the flagged offers in the hour associated with the Day-Ahead Ancillary Services have a material impact on Day-Ahead Market prices. Only if the impact test results demonstrate an impact on Day-Ahead Market prices that exceeds the impact test thresholds will the offer be subject to mitigation.

C. IMPACT TEST

Q: Please explain the impact test that the ISO designed for the Day-Ahead Ancillary Services Market.

A: The impact test sets a threshold at which Day-Ahead Ancillary Services Offers flagged as likely to be uncompetitive by the conduct test are considered to have raised Day-Ahead Prices in such a way that reflects an uncompetitive clearing outcome in the Day-Ahead Market. The objective of the impact test is to apply mitigation measures to offers that are consistent with the successful exercise of market power (*i.e.,* they materially raise price) and avoid mitigating offers that may be high, but are not consistent with the successful exercise of market power (because they do not materially raise price).

The ISO is setting the impact test threshold for each hour of the Operating Day at 150 percent of the median difference between the following:

- the conduct test threshold prices established for all Day-Ahead Ancillary Services Offers associated with the hour of the Operating Day; and
- the ISO-calculated competitive offers for all Day-Ahead Ancillary Services offers associated with the hour of the Operating Day.

An increase in any Day-Ahead Price that exceeds this threshold would constitute a violation or failure of the impact test.

The ISO-calculated competitive offers for each resource used in this calculation are the Day-Ahead Ancillary Services Benchmark Levels. These Benchmark Levels are simply the sum of the resource's Expected Close-Out Cost and Avoidable Input Cost in that hour. The Benchmark Levels are somewhat analogous to the cost-based Reference Levels the ISO uses in its energy market mitigation, in that they are intended to represent cost-based competitive offers.

Q: How will the ISO measure an increase in Day-Ahead Prices for the purpose of the impact test?

A: To measure increases in Day-Ahead Prices, the ISO will run the Day-Ahead Market's clearing engine twice. The first run, which I will refer to as the offer run, is a run of the market with all energy and Day-Ahead Ancillary Services Offers as submitted by the Market Participants. The second run, which I will refer to as the mitigation run, is a run of the market that replaces each of the Day-Ahead Ancillary Services Offer prices that exceeded the conduct test threshold with the resource's Benchmark Level.

Importantly, a Market Participant may submit different prices for each Day-Ahead Ancillary Services product, and the Day-Ahead Ancillary Services Offer potentially has four different prices. Only those prices that exceeded the conduct test threshold are replaced with the appropriate Benchmark Level in the mitigation run. Further, the ISO will conduct only one mitigation run that replaces all prices exceeding conduct test thresholds in any Day-Ahead Ancillary Services Offer submitted for that hour.

The ISO will then measure the difference between the Day-Ahead Prices observed under the offer run and those observed under the mitigation run, and any increases will be compared to the impact test threshold. Specifically, the increases measured will be increases in Day-Ahead Hub Prices, Day-Ahead Ancillary Services prices, and the Forecast Energy Requirement Price. In this way, the impact test measures the impact of presumptively uncompetitive Day-Ahead Ancillary Services offers (*i.e.,* offers that failed the conduct test) on both Day-Ahead energy prices and ancillary services prices.

Q: Why is the ISO conducting only one mitigation run that replaces all offer prices flagged by the conduct test at once, rather than conducting individual runs for each flagged offer price?

A: For a given hour, there is the potential for many resources to submit offers that are above their conduct test threshold levels. For the ISO to carry out a separate mitigation run for each and every flagged offer price in a given hour would potentially require a large number of runs (as many as the number of offer prices that fail the conduct test) for each of the twenty-four hours of a given Operating Day. It is not computationally feasible for the ISO to conduct this potentially large number of runs and post the final Day-Ahead Market results within the Day-Ahead Market clearing timeline.

Q: Please explain the significance of the median difference between conduct test threshold prices and Benchmark Levels among all resources with regard to the impact test threshold.

A: The ISO is proposing to set the impact test threshold based on the difference between the conduct test threshold levels and Benchmark Levels. This is because the range between conduct test threshold levels and Benchmark Levels represents the acceptable competitive prices if all resources stayed below their conduct test threshold (but above their Benchmark Levels).

To illustrate this, consider two Day-Ahead Market outcomes. In the first, the marginal resources set the Day-Ahead Ancillary Services prices at each corresponding marginal resource's conduct test threshold. In the second, the marginal resources set the Day-Ahead Ancillary Services prices at each corresponding marginal resource's Benchmark Level. These two market outcomes are deemed competitive outcomes because presumptively competitive offers—that is, offers that do not violate the conduct test—set Day-Ahead Ancillary Services prices in both. Thus, the difference in the prices in these two outcomes—which is the difference between the conduct test threshold price of the marginal resource in the first run and the Benchmark Level of the marginal resource in the second run—should be acceptable and not trigger mitigation. This is why the ISO is proposing to base the impact test threshold price on the difference between the conduct test threshold levels and Benchmark Levels.

The ISO proposes to use the median difference among all offering resources' conduct test threshold levels and Benchmark Levels to set the impact test threshold. The median difference will capture the difference between the conduct test threshold levels and Benchmark Levels that is representative of the typical difference between these two levels among all potential sellers of Day-Ahead Ancillary Services. In addition, the ISO chose to use a median value over other statistics, like a mean value, because a median value is robust and is not influenced or swayed by extreme outliers or skewed data.

Q: Please provide an example of the ISO's calculation of the impact test threshold.

A: For simplicity, suppose three resources offer Day-Ahead Ancillary Services into the Day-Ahead Market: two oil resources and a natural gas resource.[12] The Expected Close-Out Component calculated for the hour is \$3 per MWh. The two oil resources only face the expected close-out cost and have a Benchmark Level of \$3 per MWh. The third resource, a natural gas resource, has an Avoidable Input Cost of \$2 per MWh, and thus a total Benchmark Level of \$5 per MWh. The conduct test threshold levels for the oil resources are 2×\$3 per MWh = \$6 per MWh and for the gas resource is 2×\$3 per MWh + 1.5×\$2 per MWh = \$9 per MWh.

[12] In practice, the number of resources offering Day-Ahead Ancillary Services may well exceed a hundred.

To calculate the impact test threshold, we consider the median difference between the three conduct test threshold levels and the three Benchmark Levels. The three differences between conduct test threshold and Benchmark Levels are \$3 per MWh and \$3 per MWh for the two oil resources and \$4 per MWh for the gas resource. The median of these differences is:

$$\text{median}\{\$3 \text{ per MWh}, \$3 \text{ per MWh}, \$4 \text{ per MWh}\} = \$3 \text{ per MWh}$$

The impact test threshold price is 150 percent of the median, which is $1.5 \times \$3$ per MWh = \$4.50 per MWh. Therefore, Day-Ahead Ancillary Services Offers that violate the conduct test would collectively violate the impact test if the change in Day-Ahead Prices between the offer run and the mitigation run exceeded \$4.50 per MWh.

Q: Why is the threshold for price impacts set at 50 percent higher than the median difference between conduct test threshold prices and Benchmark Levels?

A: The ISO proposes a threshold for price impacts that is 50 percent higher than the median difference between conduct test thresholds and Benchmark Levels due to the practical limitations of how the impact test measures price changes. As explained in Section VI.C of my testimony, the ISO, due to computational constraints, performs a single mitigation run where all Day-Ahead Ancillary

Services offer prices that fail the conduct test are set at their Benchmark Levels simultaneously.

In a situation where numerous offers submitted by many different Market Participants fail the conduct test, it is plausible that each individual offer would have a small price impact and would not be mitigated if the impact test was performed on each offer separately, rather than simultaneously. However, when evaluated for impact simultaneously, it is possible that the collection of the many offer prices that fail the conduct test can have a larger price impact, leading to a failure of the impact test. These offer prices might have originated from various resources and from different Market Participants whose offers are not coordinated. An impact test threshold set at the median difference, if triggered, would treat these offers as if they are part of a single withholding strategy when in fact they are not.

To reduce the likelihood of over-mitigation and address the concern that the use of a single mitigation run might capture a set of offers that, on their own, would not cause price impacts, the ISO proposes to include this 50 percent tolerance. The ISO evaluated lower and higher multipliers of the median difference (such as 125 percent, 175 percent, and 200 percent) as well. Using the results of the MPA, it concluded that higher impact test thresholds might be ineffective in identifying impactful and profitable withholding of Day-Ahead Ancillary Services while lower multipliers might results in over-mitigation as discussed above. Hence, the

ISO proposes to set the impact test threshold at 150 percent of the median difference

D. APPLICATION OF MITIGATION

Q: What are the consequences when a Day-Ahead Ancillary Services Offer triggers both the conduct and impact tests?

A: As described above, a Day-Ahead Ancillary Services Offer triggers the conduct test when one of its prices exceeds the conduct test threshold. The offer triggers the impact test when, also as described above, the price impact observed when comparing the Day-Ahead Prices of the offer run to the mitigation run exceeds the impact test threshold. If the conduct test is violated and the impact test shows that these offers have affected Day-Ahead Clearing prices in a manner consistent with uncompetitive behavior, then each Day-Ahead Ancillary Services Offer price that triggered the conduct test threshold for the applicable hour will be set to the Benchmark Level associated with the offer. This mitigation will not extend beyond the hour associated with the Day-Ahead Ancillary Services Offer or offers that violated the conduct and impact tests.

Q: Why is the ISO mitigating all prices that exceed the conduct test thresholds in that hour down to Benchmark Levels rather than conduct test threshold levels?

A: The logic for mitigating all such prices to corresponding Benchmark Levels—which are the ISO's estimated competitive offer price levels—instead of conduct test threshold levels, which are “upper bounds” on the reasonable range of competitive Day-Ahead Ancillary Services Offer prices—is to give stronger incentives to resources to submit competitive Day-Ahead Ancillary Services offers. If resources are mitigated to their conduct test threshold level, a resource could hypothetically face no consequences in the market for attempting to exercise market power by offering its Day-Ahead Ancillary Services at extremely high prices. The worst that can happen to the resource is mitigation to the highest acceptable Day-Ahead Ancillary Services Offer prices. The proposed mitigation practice of mitigating to Benchmark Levels, rather than conduct test threshold levels, is consistent with the ISO’s current energy market mitigation design as well as other RTO and ISO mitigation designs.

Q: Why is the ISO mitigating only the prices within an offer that exceeded the conduct test threshold and not all four prices in the offer?

A: First and foremost, the proposed mitigation design aims to only target Day-Ahead Ancillary Services offer prices that exceed the conduct test threshold levels, not the presumptively competitive offer prices that are below these levels. Second, mitigating all offer prices within an offer could lead to instances of upward mitigation that would harm the market as well as the mitigated resource. Consider a case when a resource submits an offer price below its Benchmark Level for a Day-Ahead Ancillary Services product and above the conduct test threshold level for another product. If all four Day-Ahead Ancillary Services prices in the offer are mitigated to the Benchmark Level, the first offer price will be mitigated to a higher price than that submitted by the resource. The upward mitigation of the first offer price could impact the resource's ability to clear the market and receive an award for that product, and potentially deprive the market of a lower clearing price for that product.

Q: Why does the duration of Day-Ahead Ancillary Services Offer mitigation extend only to the hour associated with the mitigated offers?

A: The main reason one might consider extending mitigation beyond the associated hour is the information that a Market Participant may gain from the knowledge that it was mitigated and the potential for noncompetitive offers following its initial mitigation. That concern is not pertinent to the mitigation of the Day-Ahead Ancillary Services. The clearing of the Day-Ahead Market and possible mitigation take place after all Day-Ahead Market energy and ancillary services offers are already submitted for the entire 24 hours of the associated Operating Day. In other words, there is no possibility for a Market Participant to change its Day-Ahead Market Ancillary Services offers after possible mitigation.

Q: What is the ultimate market outcome from mitigating Day-Ahead Ancillary Services Offer prices for the hour associated with those offers?

A: Ultimately, the final market outcome, which includes financially binding Day-Ahead awards and clearing prices, will reflect the results of the mitigation run. This outcome will ensure that any potential exercise of market power that would have a significant impact on prices is avoided.

Q: Did the ISO conduct any analysis to validate that its application of mitigation using the proposed conduct and impact test framework is unlikely to either over-mitigate or under-mitigate Day-Ahead Ancillary Services Offers?

A: Yes. The ISO used the MPA simulations to evaluate and analyze the proposed conduct and impact mitigation design.

As explained in Section V above, the ISO simulated various withholding strategies across the 46 study days of the MPA, and the hours during which withholding had a meaningful impact on Day-Ahead Prices. Relying on the MPA withholding simulations, the ISO then ran simulations of the Day-Ahead Market with the conduct and impact test thresholds applied as designed across each withholding scenario. Specifically, the ISO used the proposed conduct test threshold prices to identify offers that should be flagged as having violated the conduct test in each withholding strategy. Having identified Day-Ahead Ancillary Services Offers that violate the conduct test, the ISO performed mitigation run simulations consistent with the proposed impact test for all the withholding strategies where Day-Ahead Ancillary Services Offer prices failed the conduct test. At the end of this process, the ISO had all the offer and mitigation runs at its disposal for further analysis. The ISO used the results of offer and mitigation runs to identify cases that failed the impact test. The difference between the two runs served as the basis for determining how much the conduct and impact test framework reduced the price impacts from withholding strategies.

The ISO's analysis shows that the proposed conduct and impact tests substantially reduce the overall price impacts of strategic withholding on Day-Ahead Market prices, compared to the price impacts seen in the MPA withholding simulations. For example, in the simulation in which the largest participant withheld 40 percent of its Day-Ahead Ancillary Services, application of the conduct and impact test mitigation framework resulted in reducing the price impacts from withholding by almost a factor of ten or more.[13] In this withholding case, the application of mitigation as proposed reduces the impact of strategic withholding on the average all-hour Day-Ahead Ten-Minute Spinning Reserve clearing price from $2.06 per MWh to $0.23 per MWh, almost by a factor of 10. Other Day-Ahead Prices show larger drops in overall impacts as a result of applying the mitigation as designed.

[13] The reductions in price impact resulting from the application of the ISO's proposed mitigation design in the 40-percent withholding scenario were in line with the outcomes observed across all Day-Ahead Ancillary Services withholding scenarios. For instance, the ISO's proposed mitigation design reduced the price impact on the Day-Ahead Ten-Minute Spinning Reserve product by a factor of 4 in the 10-percent withholding case (when price impact was low before the application of the ISO's proposed mitigation design) and by a factor over 40 in the 100-percent withholding case. The reductions in the price of that product in other withholding cases fell within this range. The ISO's proposed mitigation design led to more significant price reductions for other products in all these withholding cases than those observed for the Day-Ahead Ten-Minute Spinning Reserve product.

For context, for the vast majority of hours of the MPA's 46 study days, simulated withholding of even the largest suppliers did not materially impact market prices. In most conditions, robust competition and substitution prevailed and effectively disciplined uncompetitive conduct. However, as noted above, the overall harm to the market from simulated withholding dropped significantly with mitigation as proposed in the hours that competition was not able to discipline the simulated exercise of market power.

E. CONSULTATION PROCESS AND FUEL PRICE ADJUSTMENTS

Q: You have previously mentioned that Market Participants may seek to adjust the Expected Close-Out Component and Avoidable Input Costs that are used to calculate their Benchmark Levels and conduct test thresholds. Please explain what the consultation process is and how Market Participants may use it.

A: The ISO's existing mitigation rules for the ISO's energy markets currently include a consultation process, whereby a Market Participant may request (or the IMM may initiate) a discussion between the IMM and the Market Participant regarding the information and analysis used to determine Reference Levels used as part of energy market mitigation. The ISO proposes to leverage the existing consultation process to allow Market Participants submitting Day-Ahead Ancillary Services Offers to consult with the IMM regarding the information and analysis used to determine a resource's Benchmark Levels, which necessarily includes the Expected Close-Out Component and Avoidable Input Costs that make up Benchmark Levels. The ISO also proposes to leverage the fuel-price adjustment process that exists today as part of the energy market mitigation rules to allow Market Participants with natural gas resources to seek adjustments to the resources' Avoidable Input Cost, along with adjustments to the Reference Level to its Supply Offer, when natural gas prices exceed those used by the IMM in calculating Reference Levels and Benchmark Levels.

Generally, Market Participants are expected to consult with the IMM about their Benchmark Levels, if they so choose, far enough in advance of the Operating Day associated with the Day-Ahead Ancillary Services Offer that the consultation can be completed no later than 5:00 p.m. on the second business day prior to the Operating Day. The consultation process will remain available between this time and up to 30 minutes prior to the close of the Day-Ahead Market (that is, when Day-Ahead offers are due) for events occurring within the 24-hour period prior to the Operating Day that may impact the cost components of a Day-Ahead Ancillary Services Offer. Market Participants engaging in consultation are required to submit all verifiable costs and other supporting data necessary for the IMM to determine that adjustments to the Benchmark Level and its components are warranted. The IMM will not be able to adjust either of the Benchmark Level components without verifiable data to support the adjustment.

Q: You mentioned that the ISO will calculate Expected Close-Out Components that will be the same for every resource in a given Day-Ahead Ancillary Services Offer hour. Please explain how the consultation process will apply to Expected Close-Out Components.

A: The ISO anticipates that there may be circumstances under which a Market Participant disagrees with the ISO-determined Expected Close-Out Component based on its own model of the range of expected Real-Time Hub Prices and potential close-out charges that the Market Participant might incur. In such a case, the Market Participants may consult with the IMM about the participant's expected close-out model as part of the general consultation process. Namely, the ISO expects Market Participants to seek IMM review and approval of the model by submitting it well in advance of the two-business-day consultation process deadline, providing sufficient time for the IMM to analyze the model.

If the IMM determines that the model is sufficiently supported, the IMM would then allow the Market Participant to submit the expected close-out costs based upon this model going forward, depending on the model's appropriateness for varying market conditions. The criteria for the evaluation of a Market Participant's model would involve evaluating the model using similar metrics and criteria to those the ISO used to evaluate its GMM, which are explained in Section III of my testimony. Yet, the IMM may evaluate a proposed model based on other criteria as appropriate to the model being evaluated at the time of evaluation.

The ISO also anticipates there may be circumstances where Market Participants disagree with the ISO's expectations (as reflected in GMM results) of the level of risk and volatility expected during the Operating Day and how that might impact Real-Time Hub Prices. The consultation process will provide the Market Participant with the opportunity to consult with the IMM about the appropriateness of the "two times the Expected Close-Out Component" aspect of the conduct test threshold price on a case-by-case basis. For example, assuming that the Market Participant is able to support, with objective, verifiable data, that it should be allowed a larger risk premium above its Expected Close-Out Component than would be allowed under normal conditions, the IMM would then be empowered to treat the Market Participant's offer price or prices as not violating the conduct test.

Q: Regarding the Avoidable Input Cost component of the Benchmark Level, will a Market Participant be allowed to consult with the IMM if it believes it has avoidable costs associated with providing Day-Ahead Ancillary Services that are not already recognized by the way the ISO calculates the Avoidable Input Cost?

A: Yes. The Market Participant will have an opportunity to consult with the IMM regarding costs that it believes are truly incremental—that is, avoidable—to its provision of Day-Ahead Ancillary Services in the hour or hours associated with its offer or offers. If the Market Participant is able to support its claim that some other cost should be recognized as an input cost with verifiable information and analysis that demonstrates the incremental nature of the cost, then the IMM will be empowered to either adjust the resource's Avoidable Input Cost or otherwise treat the associated Day-Ahead Ancillary Services Offer or offers as not violating the conduct test.

Q: Please explain how the existing fuel-price adjustment process is available to Market Participants submitting Day-Ahead Ancillary Services Offers.

A: The existing fuel-price adjustment process currently allows Market Participants to submit fuel prices that meet certain conditions described in Section III.A.3.4(a) of Appendix A to Market Rule 1 to the IMM for use in determining a resource's Reference Levels related to energy offers. When a fuel price meets the necessary conditions, the submitted fuel price will be used. As set forth in Section III.A.3.4(b), the Market Participant must then submit verifiable information and analysis to support the fuel price within five business days of the price's submittal. As described in Section III.A.3.4(c), failure to properly support a fuel price may lead to an extended period during which the Market Participant is effectively locked out of using the fuel-price adjustment process.

The ISO proposes to modify the fuel-price adjustment process such that fuel prices submitted through this process are also used for calculating Avoidable Input Costs for natural gas resources. For a fuel price submitted through this process to be used in the Avoidable Input Cost calculation, it must meet all the same conditions that currently apply in Section III.A.3.4(a), and it will be subject to the same verification requirements set forth in Section III.A.3.4(b). The ISO intends for the fuel-price adjustment process to be one singular process where a fuel price submitted to apply to a Reference Level is also applied to any corresponding Avoidable Input Cost for determining a Benchmark Level. Namely, if the fuel price submitted will be used to adjust mitigation threshold values for a specific hour or set of hours in the Operating Day, it will be used to adjust those values that apply to both the energy and ancillary services offers associated with the hour or set of hours.

F. OPPORTUNITY FOR COST RECOVERY

Q: Will Market Participants have any recourse if they feel that their Day-Ahead Ancillary Services Offer was unnecessarily or inappropriately mitigated?

A: Yes. Currently, Section III.A.15.2 sets forth a process by which Market Participants may submit a Section 205 filing when the Market Participant believes that it will not recover certain actual costs that it reflected in its energy offer as a result of mitigation by the ISO. This existing process requires the Market Participant to compile a filing that demonstrates its actual costs experienced as a result of producing energy during the hour or hours associated with the mitigated energy offer and an explanation as to why such costs exceeded the costs reflected in the resource's Reference Level. The resource submits these materials to the IMM, and the IMM provides a written explanation of the events that resulted in the Section 205 cost recovery request. The Market Participant adds this written explanation to its filing, as well as any request to recover regulatory costs associated with making the Section 205 filing, and then submits this entire package to the Commission. The Commission then determines what cost recovery is due to the Market Participant.

The ISO intends to leverage this cost recovery process to also allow for cost recovery resulting from the mitigation of Day-Ahead Ancillary Services Offers. Thus, Market Participants will also be able to file a Section 205 cost recovery filing to recover actual close-out or incremental (that is, avoidable) input costs incurred by the resource as a result of inappropriate offer mitigation. However, the ISO is making certain clarifications and adjustments to the process that are necessary in light of the nature of the costs associated with Day-Ahead Ancillary Services Offers. The ISO is also including a process by which Market Participants with Day-Ahead Ancillary Services Offers may recover opportunity costs that result from inappropriate mitigation of a Day-Ahead Ancillary Services Offer.

Q: Please explain the clarifications and adjustments the ISO proposes to the cost recovery process associated with energy offer, and now Day-Ahead Ancillary Services Offer, mitigation.

A: The ISO is adjusting the Tariff language in Section III.A.15.2 of Appendix A to Market Rule 1 to clarify that a Market Participant must submit documentation and information supporting the basis for the Market Participant's original, submitted offer. The documentation and information must show that offer, at the time submitted, reflected the Market Participant's reasonable expectation of the costs it would incur by providing the energy or ancillary service product. Additionally, the Market Participant also must explain why the original offer should not have been mitigated to the resource's Reference Level or Benchmark Level, depending on which mitigation purportedly caused the costs for which recovery is sought.

This clarification and adjustment is important in light of how Day-Ahead Ancillary Services Offers are formulated and actual costs are incurred. At the time of the offer, the Market Participant can only make predictions (or accept ISO-determined predictions) about the close-out charge it expects to incur the next day. Given the dependence of certain Avoidable Input Costs on electricity prices (notably, the costs to storage), offers must also incorporate some prediction of those costs as well. The Benchmark Levels created by the ISO for the Day-Ahead Market are also the result of estimation and prediction. Consequently, the important inquiry into whether a Day-Ahead Ancillary Services Offer should have been mitigated is what the Market Participant anticipated its actual costs would be at the time of the offer and why, based on those costs, its offer should not have been mitigated to the Benchmark Level.

Q: Please elaborate on the process by which a Market Participant may seek opportunity costs incurred due to the mitigation of its Day-Ahead Ancillary Services Offer.

A: The ISO is including in its revisions to the Section 205 cost recovery process an opportunity for Market Participants to seek opportunity costs that the resource incurred as a result of the mitigation of its Day-Ahead Ancillary Services Offer. This request may be included as part of a recovery of direct costs, such as close-out or input costs, or it may be made independently. The Market Participant, however, may only seek opportunity costs related to opportunity costs that it incurred within the Day-Ahead Market itself.

Q: What do you mean when you say that the Market Participant may only seek opportunity costs incurred within the Day-Ahead Market itself?

A: An opportunity cost within the Day-Ahead Market is the cost associated with being mitigated in such a way that the resource clears for one Day-Ahead product instead of a different Day-Ahead product for which the resource would have cleared but for the application of mitigation. It is the cost associated with the lost opportunity of being unable to clear for this more profitable Day-Ahead product, for which the resource would have cleared if the ISO had let its original Day-Ahead Ancillary Services Offer prices remain as submitted. Market Participants will not be allowed to seek recovery of other opportunity costs beyond this narrowly defined set of opportunity costs within the Day-Ahead Market.

Q: Please provide an example of circumstances under which a Market Participant would incur opportunity costs within the Day-Ahead Market.

A: Consider an example in which a resource would not have cleared for Day-Ahead Ancillary Services but for mitigation and would have instead cleared for Day-Ahead energy in a way that was more profitable. To determine the opportunity cost that resulted from *not* clearing for Day-Ahead energy, two sets of calculations that need to be performed. One calculation is to determine the net revenue for the case in which the resource's Day-Ahead Ancillary Services Offer *is* mitigated and the resource receives a Day-Ahead Ancillary Services award. The second calculation is to determine the net revenue for the case in which the Day-Ahead Ancillary Services Offer was *not* mitigated and in which the resource would have received a Day-Ahead energy award and no Day-Ahead Ancillary Services award. For simplicity, we assume that the resource does not deliver energy or reserves in Real-Time in this example. This assumption does not affect the generality of the example because the resource's Real-Time revenues are identical in both cases and therefore, do not impact the opportunity cost calculation.

For the first case, the net revenue associated with the mitigation is the clearing price for its Day-Ahead Ancillary Services award net of any close-out charge in Real-Time (which is based on the Real-Time Hub Price). In the second case, the net revenue associated with not mitigating the resource is the Day-Ahead LMP for its Day-Ahead energy award, net of the corresponding Real-Time LMP. The net revenue is net of the corresponding Real-Time LMP because of the assumption that the resource does not have any Real-Time energy or reserves revenues.

Comparing these two net revenues, the opportunity cost for the resource is the difference between the Day-Ahead outcomes (Day-Ahead LMP minus the Day-Ahead Ancillary Services clearing price), net of the difference between Real-Time outcomes (Real-Time LMP minus the close-out charge). Ultimately, this calculation yields the resource's lost profits that resulted from clearing for the Day-Ahead Ancillary Services product rather than energy, due to mitigation.

In this example, an opportunity cost may exist if the Day-Ahead LMP at the resource's location is particularly high while the Real-Time LMP at the same location is particularly low. It is important to note, however, that an opportunity cost of the type of this example should be rare.[14]

Q: How does the ISO treat revenues a resource may earn in Real-Time operations if it submits a cost recovery request associated with Day-Ahead Ancillary Services Offer mitigation?

A: The ISO will not reduce a Market Participant's claimed Day-Ahead Ancillary Services losses for which it may seek cost recovery by its Real-Time energy market revenues. This is because such netting across markets can inefficiently

[14] The limited congestion within the ISO-New England footprint generally results in LMPs that are close to the Hub Price in both Day-Ahead and Real-Time. More specifically, in Real-Time, limited congestion makes it unlikely for a resource to face a significant close-out charge on its Day-Ahead Ancillary Services award while the Real-Time LMP at its location remains relatively low.

alter the incentive to offer in Real-Time Energy Market. If claimed cost recovery losses are reduced by Real-Time revenues or profits, a participant that expects to make a cost recovery claim related to Day-Ahead Ancillary Services mitigation may have an incentive to show smaller Real-Time profits so that it is able to petition for a higher amount of claimed losses. It may act on this incentive by raising its Real-Time energy offers to avoid clearing for energy in Real-Time, or reduce the net profits of Real-Time delivery of energy and reserves, if cleared. This could result in inefficient market outcomes in Real-Time.

Q: How does the ISO anticipate Market Participants will calculate such opportunity costs for the purpose of their Section 205 filings?

A: The ISO anticipates that a Market Participant will have sufficient publicly-available market outcome information from which to calculate opportunity costs incurred as a result of mitigation that caused Market Participant's resource to clear for a less profitable product. The example above demonstrates both the calculation and the information needed for the calculation in the case of mitigation that leads to clearing a less profitable Day-Ahead product (Day-Ahead Ancillary Services, in this case) instead of a more profitable Day-Ahead product (energy).

VII. PHYSICAL WITHHOLDING MITIGATION

Q: How does the ISO intend to address attempts at physical withholding of Day-Ahead Ancillary Services?

A: The ISO has set conduct and impact thresholds to guide the IMM's identification of physical withholding that are similar to the thresholds that currently guide the IMM's identification of physical withholding in the ISO's energy markets. Similarly, physical withholding will occur through the *post hoc*, Commission-referral process that exists today to redress instances of physical withholding in the energy markets.

Q: Please describe the conduct and impact thresholds the ISO proposes to set to guide the IMM's identification of instances of physical withholding.

A: For background, the IMM is currently empowered to refer instances of physical withholding to the Commission, with physical withholding in the ISO's Tariff being defined generally as "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."[15] The IMM is empowered by the ISO Tariff to monitor the markets for instances of physical withholding and, if it identifies any such instances, refer them to the Commission for redress, including potential sanctions. Although the IMM may consider any number of factors in making its determination of whether there exists an instance of physical withholding

[15] Section III.A.4.1 of Appendix A to Market Rule 1.

warranting referral to the Commission, the Tariff includes conduct test thresholds and impact test thresholds that the IMM may rely on to guide its inquiry.

The ISO proposes to use this same framework by which the IMM will monitor the Day-Ahead Ancillary Services Market for instances of physical withholding, including setting conduct test and impact test thresholds to guide the IMM's inquiry. Specifically, the ISO has set a conduct test threshold for physical withholding that is the greater of 20 percent or 100 MW of the total Day-Ahead Ancillary Services capability of the Market Participant's resources (*i.e.*, a Market Participant's portfolio of resources, collectively). The impact test threshold is the same threshold established for economic withholding, which is a price impact that exceeds 150 percent of the median difference of all conduct test thresholds for offers submitted for the hour and all Benchmark Levels for offers submitted for the hour.

Q: Why did the ISO set a conduct test threshold that is the greater of 20 percent or 100 MW of the total Day-Ahead Ancillary Services capability of the Market Participant's resources?

A: The ISO had several considerations in setting the automatic screening threshold for evaluation of physical withholding. First, the screening threshold needed to accommodate changes to ancillary service capabilities that are the result of routine physical variation in resources' capabilities. Second, it should account for the many small resources and participants with relatively little ancillary service capability that—based on the MPA simulation study results—are very unlikely to be impactful. Third, it should screen potentially impactful physical withholding behavior that has the potential for failing the impact test, if the withholding was part of an economic withholding strategy. Fourth, the screening threshold should account for the potential portfolio benefits a successful physical withholding strategy would entail, which is why the ISO is proposing to set the screening threshold at the portfolio level.

When it conducted the MPA withholding simulations, the ISO observed that withholding by any Market Participant of 100 MW of Day-Ahead Ancillary Services capability—whether through economic or physical withholding—had either no impact or, in rare cases, an inconsequential impact on Day-Ahead Prices. Similarly, the ISO also observed in the withholding simulations that when the first, second, and third largest suppliers withheld 20 percent of their ancillary services capability that such levels of withholding also generally either had no impact or an inconsequential impact on Day-Ahead Prices. These two values, then, provide a threshold that will avoid flagging behavior as potential physical withholding when that behavior could not result in a profitable exercise of market power or harm the market.

The requirement that the withholding be the higher of 20 percent or 100 MW effectively sets the threshold at 100 MW or above. Thus, smaller resources (in small portfolios) with little-to-no ancillary service capability, like small wind-energy resources, would not be unnecessarily flagged by this threshold. This 100 MW minimum threshold also accommodates routine variations in resource capabilities, including those caused by factors like seasonal changes to the ancillary service capabilities, or variation of ancillary service capability across the dispatch range of the resource that cannot be fully reflected due to technical limitations of the Day-Ahead Market software.

Q: How will the ISO determine the Market Participant's resources' total Day-Ahead Ancillary Services capability for the purpose of determining the conduct test threshold?

A: For the purpose of determining a Market Participant's Day-Ahead Ancillary Services capability, the ISO will consider the resources' physical characteristics (*e.g.* CLAIM10 and CLAIM30 capabilities, ramp rates, maximum operating limits, etc.) in determining the total ancillary service capability of the resource. The ISO will also consider, in accordance with Section III.A.4.2.2, any unjustified de-ratings when calculating the total ancillary service capability. For example, the CLAIM30 capability of a fast-start resource that has an energy offer but remains offline (*i.e.*, is not committed for energy) in the Day-Ahead Market and does not offer any ancillary service capability into the Day-Ahead Market could be the appropriate measure for ancillary service capability. If the same resource is online (*i.e.*, is committed for energy) in another run of Day-Ahead Market but still does not offer any ancillary service capability into the Day-Ahead Market, its ramp rate and maximum output limit could be used to calculate appropriate ancillary service capability. Consistent with the portfolio-level design of the physical withholding threshold (*i.e.*, the threshold applies to all of a Market Participant's resources collectively), ancillary service capability for purposes of the physical withholding conduct threshold will be the aggregate capability of the Market Participant's resources.

Q: Please elaborate on the impact test threshold for the physical withholding inquiry.

A: Under the ISO's current physical withholding rules for the energy markets, the IMM will first consult with the target Market Participant to determine if there is an explanation for the offer behavior that appears to be a possible instance of physical withholding. If the consultation does not result in an adequate explanation as to why the behavior is economic and not an attempt to exercise market power, the IMM will proceed to conducting a price impact analysis.

For the Day-Ahead Ancillary Services Market, the ISO proposes to continue this same practice of consultation followed by a price impact analysis, if necessary. The price impact analysis, should the IMM perform one, will mirror the analysis described above for the economic withholding impact test. Specifically, the IMM will conduct both an offer run and a mitigation run of the Day-Ahead Market. The mitigation run will include the MWs of Day-Ahead Ancillary Services capability that the resource appears to have uneconomically withheld from the market. The IMM will then compare the Day-Ahead Prices in the offer run to the mitigation run to determine if there was any price increase that exceeds the impact test threshold amount described above.

Q: If the IMM determines that a Market Participant's offer behavior violates both the conduct test and the impact test thresholds, will the IMM automatically refer that resource to the Commission?

A: No. The IMM's physical withholding inquiry is flexible enough that it can take a holistic view of the Market Participant's offer behavior, evaluating any relevant factors to determine whether the potential withholding appears to have been uneconomic, absent market power. The ISO's physical withholding rules for the energy market, and now also proposed for the Day-Ahead Ancillary Services Market, do not dictate automatic referral if conduct and impact test thresholds are violated.

Q: If a Market Participant experiences an outage due to equipment failure or has a serious concern about the financial risk of taking on a Day-Ahead Ancillary Services award such that it wishes to refrain from offering its ancillary services capabilities into the Day-Ahead Market, should it be concerned that its failure to offer into the Day-Ahead Ancillary Services Market will result in a referral to the Commission?

A: No. Market Participants that have valid operational or economic rationales for failing to offer their resources' ancillary service capabilities into the Day-Ahead Ancillary Services Market should not be concerned about referrals to the

Commission. Importantly, the ISO Tariff already clearly defines physical withholding as the withholding of a service when it is in the economic interest of the resource (absent an exercise of market power) to provide that service.

Moreover, the consultation process described above is available to Market Participants in advance of the close of the Day-Ahead Market, and the IMM has encouraged, as part of the stakeholder process regarding this proposal, Market Participants to approach the IMM to explain concerns about being flagged for physical withholding whenever those concerns arise. Consultation in advance of the close of the Day-Ahead Ancillary Services offer period presents an opportunity for concerned Market Participants to explain why their decision not to offer is either unavoidable or uneconomic (absent market power) and also spares IMM resources that might otherwise be expended in conducting a *post hoc* inquiry into the Market Participants behavior. And even where a *post hoc* inquiry occurs, the IMM's consultation with the Market Participant prior to conducting an impact test provides an opportunity for the Market Participant to explain its offer behavior.

VIII. CONCLUSION

Q: Does this conclude your testimony?

A: Yes.

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

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